THE 1970 NATIONAL POWER SURVEY

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THE 1970 NATIONAL POWER SURVEY

FEDERAL POWER COMMISSION

PART II

ADVISORY REPORTS TO THE FEDERAL POWER COMMISSION

PREPARED BY

THE NORTHEAST REGIONAL ADVISORY COMMITTEE

THE EAST CENTRAL REGIONAL ADVISORY COMMITTEE

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FOREWORD

In January 1966, the Federal Power Commission established six Regional Advisory Committees to assist the Commission in updating the National Power Survey through the development of individual regional reports.

The reports of the Regional Advisory Committees compose Volumes II and III of the full survey report. The information supplements that of the Commission's own report in Volume I, and includes a wealth of data which will be of interest to reviewers concerned with power system organizations and practices in the different regions, the projected loads for the future, and the anticipated means of meeting these loads to the year 1990.

As in all Commission Advisory Committee activities, the Commission's staff has participated in the deliberations of the Committees. While consultation and suggestions have been freely exchanged by the Committees and staff, the final reports are the products of the Committees.

We gratefully acknowledge the participation of the members of the Regional Advisory Committees and the many others who assisted them in these studies. Memberships of the individual Regional Advisory Committees are shown in the corresponding report sections of this volume.

THE FEDERAL POWER COMMISSION.

PART II

CONTENTS

ELECTRIC POWER IN THE NORTHEAST

1970 - 1980 - 1990

A REPORT
TO THE FEDERAL POWER COMMISSION

PREPARED BY
THE NORTHEAST REGIONAL ADVISORY COMMITTEE

DECEMBER 2, 1968

PREFACE

On January 24, 1962, the Federal Power Commission announced plans for conducting a National Power Survey. The ensuing studies were carried out by the Commission and its staff, with major assistance from Industry Advisory Committees established to assist with the preparation of technical material and to provide consultations and advice. The report, published in 1964, was intended to provide a guide for future planning by the electric power industry, and to provide a general reference document for statistical and technical data associated with power developments.

The electric power industry is a dynamic one, changing from day to day to meet new demands and to reflect new technologies. It was recognized at the time the National Power Survey was undertaken that the published report would soon be out-dated by progress made by the industry, and plans were developed for up-dating the survey at about five-year intervals. In line with this intent, the Federal Power Commission issued an Order on July 7, 1965, establishing six Regional Advisory Committees composed of representatives from all segments of the electric power industry. The Order was rescinded by a slightly revised Order dated January 10, 1966. The revised Order says, in part:

1. Purpose. The Regional Advisory Committees will assist the Commission and the Executive Advisory Committee in its work with and for the Commission and specifically in encouraging the utility systems in each Region to pursue courses of action consistent with the broad goals of the National Power Survey, in reporting the progress being made in attaining these goals, and in up-dating the guidelines of the Survey. The Committees will facilitate the exploration of all practicable opportunities for more efficient and reliable development and operation of power systems in each region. Meetings of the Committees will constitute forums for the exchange of ideas and for fostering better communication and understanding among all segments of the utility industry in the region. All systems of every segment of the industry would be encouraged to support the analyses through expressions of their needs and desires. The Committees will be consultative only, and they will operate within the limits established by the Commission, recognizing the appropriate corporate and public responsibilities of utility systems, and will function in keeping with the position of the Commission enunciated on many occasions that the National Power Survey is not intended as a blueprint or as a means of compelling the construction of particular facilities.

Each of the six Regional Advisory Committees was requested to prepare a report covering the existing power developments in its Region, and setting forth its views as to the proper course for future power developments in its area, considering current and anticipated new technology, anticipated Regional growth patterns, and other pertinent factors. The report contained herein is the result of the studies made under the guidance of the Northeast Regional Advisory Committee.

The basic materials for and preliminary drafts of this report were prepared by Task Forces [1] on Base Load Generation, Peaking and Quick Start Generation, Transmission, and Coordination, all under the general guidance of a Coordinating Committee.[1] In addition, the Chapter on Fuels was abstracted from a report prepared by a three-region Committee [1] that analyzed the fuels resources and needs for the eastern portion of the United States, all of which is supplied from the same basic fuel sources. The staff of the New York Regional Office of the Federal Power Commission provided basic data and assistance to each of the task forces. The Task Force reports of Region I were reviewed by Advisory Committee representatives of adjacent regions to check for interregional compatibility.

The members of the Northeast Regional Advisory Committee [1] are deeply appreciative of the efforts of all of those who participated in the preparation of this report, recognizing that the work involved was an added assignment superimposed on regular activities. The Committee members believe that the plans discussed herein provide a broad framework within which future proposals can be evaluated without limiting the alternatives that may be available for meeting the desired objectives.

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[1] Membership shown in Appendix E.

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SUMMARY

Area and Scope

The Northeast Regional Advisory Committee is concerned with the geographical area designated as Region I by the Federal Power Commission. It encompasses, essentially, the eleven northeastern states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont, together with the District of Columbia. While the Region constitutes only approximately 6 percent of the total continental United States area, about 27 percent of the nation's population reside within its boundary.[1] The largest population concentrations are the metropolitan areas in conjunction with the major cities on the eastern seaboard. The Region's power supply areas and study areas are shown in Figure 1.

In terms of the electric power industry, the Region is known as the electrical combination of the New England Power Pool (NEPOOL), the New York Power Pool (NYPP), and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). Each of the three interconnected pools coordinates the planning, engineering, and operation of its facilities. Jointly, they comprise a regional electrical combine which operates a well-coordinated regional electrical network. In addition to internal coordination, the regional entities work closely with neighboring systems and pools. As electricity demands grow, and the systems become more tightly interconnected through the installation of additional transmission lines, the problems of coordination will become more complex. The Region continues to strive for the high degree of coordination necessary for reliable power supply at the lowest possible cost to the public, and has recently implemented new mechanisms to augment the relatively high degree of coordination that is currently practiced.

This report presents a preliminary view of the generation and transmission addition patterns expected to develop to the year 1990 for the northeastern segment of the electric power industry. It discusses expected future technological developments, considers increased demands for reliable bulk power supply, and recognizes a public concern for environmental factors such as air pollution, water thermal effects, and utility plant appearance. The report is concerned primarily with the problems of bulk power supply, and so does not deal directly with questions related to power distribution systems.

Peak Load Forecasts

Table I shows the 1970 to 1990 peak load forecasts and capacity requirements for the Northeast Region. The peak load estimates have been determined using as assumptions average or normal weather, and business activity progressively increasing to meet expanded consumer demand and to support a continuation of some limited military activities.

Study Area A (New England) has an almost constant annual peak load increase of approximately 6.6 percent from 1970 to 1990, resulting in a peak load value in 1990 that is approximately 3.5 times the 1970 level. Study Area B (New York) shows an initial annual peak load increase in PSA–3 (Upstate) of 5.2 percent from 1970, gradually declining to 5.1 percent by 1990, while PSA–4 (Downstate, New York City) has an initial 6 percent annual increase, declining to 5.2 percent in the final year. PSA–3 shows a 1990 peak load that is 2.7 times that of 1970, while the PSA–4 load increases by a multiple of 2.9. The Study Area C (Pa., N.J., Md., Del., D.C.) annual load growth ranges from 7.7 percent in 1970, to 5.8 percent in 1990 with an overall growth factor of 3.3 times the 1970 load.

In estimating total Region I loads, allowances were made for usable diversities resulting from non-coincident peaks between study areas. Estimated reserve and other contingency requirements were then added to develop the total capacity requirement figure shown on Table 1, to be used as a guide for long-range planning. The installed reserve requirements shown for 1980 and 1990 for planning purposes are higher than would be neces-

[1] 1960 Census Data.

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FEDERAL POWER COMMISSION

NORTHEAST REGIONAL ADVISORY COMMITTEE
REGION I
POWER SUPPLY AND STUDY AREAS

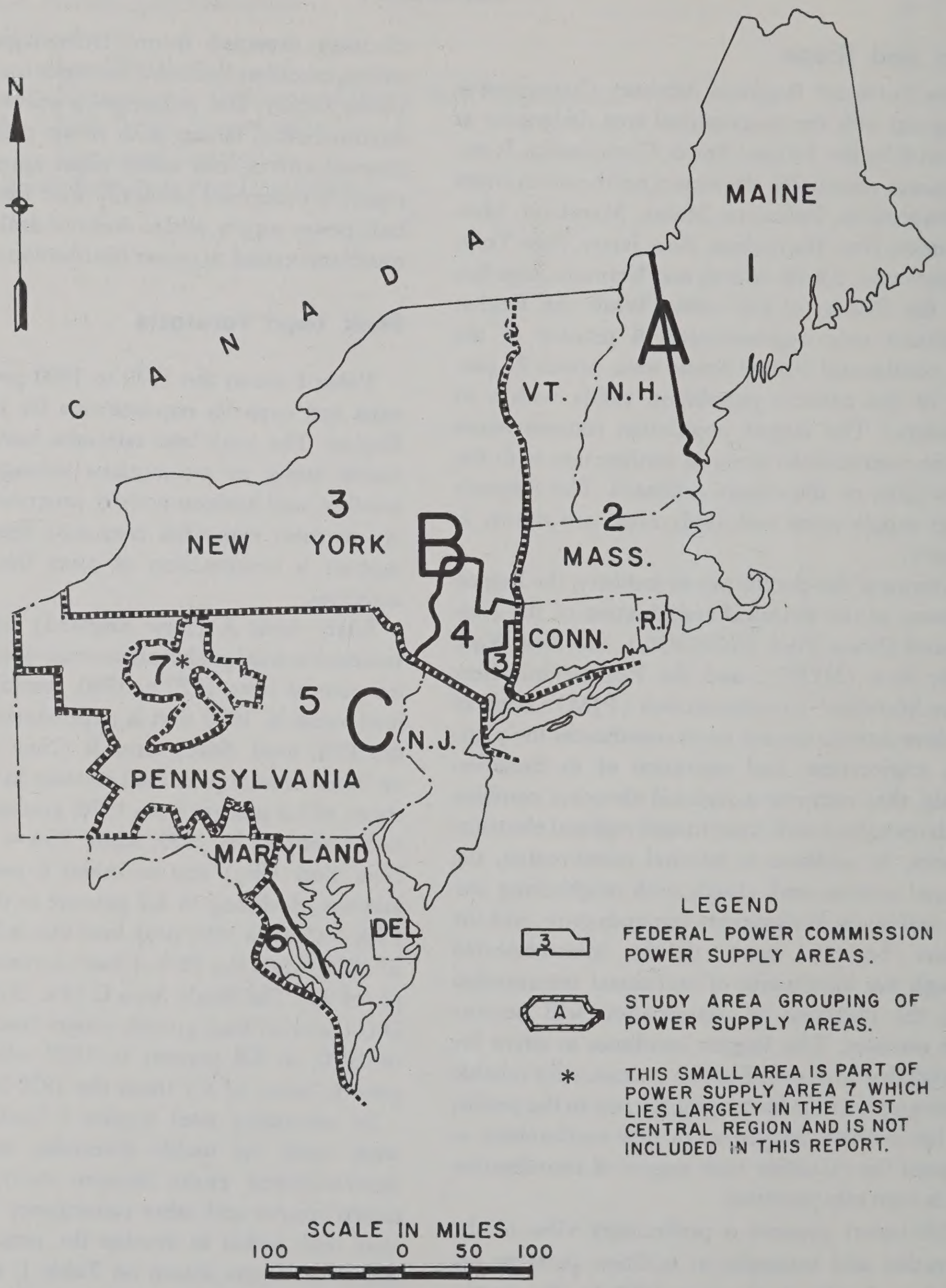


Figure 1

TABLE 1

Region I—Estimated Annual Peak Demands and Capacity Requirements

[By Power Supply Areas in Region I]

Power supply area		1970	1975	1980	1985	1990
1 and 2	Winter Peak (Mw)	11, 800	16, 200	22, 100	30, 200	41, 300
	Energy (GWH)	58, 340	80, 700	111, 000	152, 700	209, 800
3	Winter Peak (Mw)	7, 730	9, 850	12, 600	16, 150	20, 650
	Energy (GWH)	46, 100	58, 700	74, 900	95, 700	122, 100
4	Summer Peak (Mw)	9, 930	12, 900	16, 700	21, 800	28, 600
	Energy (GWH)	48, 700	64, 400	85, 100	111, 700	147, 200
5 and 6	Summer Peak (Mw)	24, 120	33, 710	45, 270	60, 530	80, 190
	Energy (GWH)	129, 380	181, 310	244, 260	327, 700	435, 500
Reg. I	Non-Coincident Peak (Mw)	53, 580	72, 660	96, 670	128, 680	170, 740
Reg. I	Coincident Peak (Mw)[1]	51, 230	69, 590	92, 770	123, 770	164, 640
Reg. I	Reserve Capacity (Gw)	11, 117	....	24, 110	....	48, 770
Reg. I	Reserve Capacity (Percent)	21. 7	....	26. 0	....	29. 6
Reg. I	Total Capacity Required (Gw)[2]	62, 347	....	116, 880	....	213, 410
Reg. I	Energy (GWH)	282, 520	385, 110	515, 260	687, 800	914, 700

[1] Table 2, Chapter I.

[2] Table 18, Chapter IX.

NOTE.—Mw=1000 Kw, Gw=1,000,000 Kw.

sary or desirable if the loads and available capacities at these times could be precisely predicated now. Experience has demonstrated, however, that load forecasts tend to be low, lead times that are actually required are often longer than anticipated, and other factors beyond the control of the utilities tend to leave system operators with less dependable reserves available than had been anticipated when initial plans were made. The relatively low reserve shown on Table 1 for some areas for 1970 are cases in point. While the general reserve requirement studies outlined in Chapter 5 and the general policies of utilities in Region I would both require attained reserves in the 15 to 20 percent range, unforeseeable circumstances have narrowed the leeway between anticipated 1970 loads and the capacity that can be made available within current construction commitments to the lower-than-planned figures. In order to minimize the consequences of errors in load forecasting and lead-time estimating that are inherent potentialities in any long-range study, the Advisory Committee considers it prudent to set future capacity targets at progressively higher limits than short-range reserve requirement studies might suggest. It is a relatively simple matter to delay a planned generating facility for a year or more if last-minute studies show that the capacity will not actually be needed as previously scheduled. It is virtually impossible to accelerate a project a year or more if the final studies show such an acceleration to be desirable.

Generation

Figures 2 and 3 portray anticipated regional generation and transmission additions during the 1970–1980 and the 1970–1990 periods, respectively. It is expected that the regional power suppliers will be required to finance and install over 150,000 megawatts of additional generation to supply a total of 165,000 megawatts as the coincident peak load in 1990.

The studies reflected in Figures 2 and 3 included consideration of changing technological developments which can minimize electric rates to the consumer. Of these developments, advancements in the field of metallurgy and nuclear reactor design have been particularly significant. The general public interest in appearance or aesthetics of power plants and in air pollution control have been taken into account, and while meeting these desires requires additional costs, such action is considered necessary.

The comparatively low cost fossil-fuel supply areas in the western Pennsylvania coal fields are utilized to the extent practicable. However, the combination of high transportation costs to load centers and anticipated stringent air pollution con-

trol may make the cost of additional high efficiency fossil-fired generation prohibitive to the utility, and ultimately to the consumer, in most parts of the Northeast. Cooling water resources, necessary for any type of electric generating equipment, are limiting factors in most of the inland areas of Region I.

Recent enthusiasm about nuclear reactor types of generating equipment is evidenced in the projections in this report. The installation of large nuclear generating plants located on or near the eastern seaboard holds great promise for all interests in the future. With plants relatively near the population and load concentrations, transmission costs would be comparatively reduced. At the same time, growing air pollution problems would be alleviated, while ensuring reasonable and tolerable power generating costs. It is also anticipated that ample supplies of cooling water will be available in the coastal areas through 1990, although cooling towers may be required at some tidal plants.

Both large fossil-fired and nuclear generating type plants are included in projected additions, in the role of carrying the base electric system load. Pumped-storage hydro generating plants have been included to share the job of carrying peak loads. Although gas or oil-fired peaking turbines and limited quantities of conventional hydroelectric generation capacity will also be installed during this period, they are not shown separately on the maps, although they are tabulated in the main body of this report. The optimum combination of base load, intermediate, and peaking units must be determined by specific studies, but preliminary analyses suggest a mix by 1990, of 40, 45, and 15 percent, respectively. It is anticipated that the 1990 generating capacity will be about 8 percent diesel or gas turbine, 3 percent conventional hydro, 7 percent pumped storage, 24 percent fossil-fueled thermal, and 58 percent nuclear.

Transmission

The addition of future generation in the Region to serve growing consumer demands will create a need for expansion of the transmission network. New transmission at existing lower voltage levels will be added. Where necessary, because of heavy power flows and longer distances, transmission at higher voltages will be installed to preserve the regional integrity and service quality. The existing backbone transmission an anticipated EHV additions to 1980 and 1990 are shown on Figures 2 and 3. The anticipated additions involve about 2,750 miles of 345-Kv lines, 1,330 miles of 500 Kv, and 1,320 miles of 765-Kv line between 1970 and 1990.[2]

Location Considerations

Nuclear plant site locations shown on Figures 2 and 3 provides a reasonable balance between load and required capacity additions within geographical boundaries of each area, and where practical, for individual companies. It has been assumed that metropolitan nuclear plant locations will be feasible during this period as operating experience is gained. Considerations as to cooling water availability and limitations, land geography, and appearance aesthetics were factors in the siting selection.

Limitations peculiar to siting fossil-fueled units such as air pollution, coal handling and storage, fuel cost attributed to transportation, and ash disposal were all weighed in the selection of the geographical locations. Aesthetics, natural resources, and existing plant facilities were considerations in basic site selection.

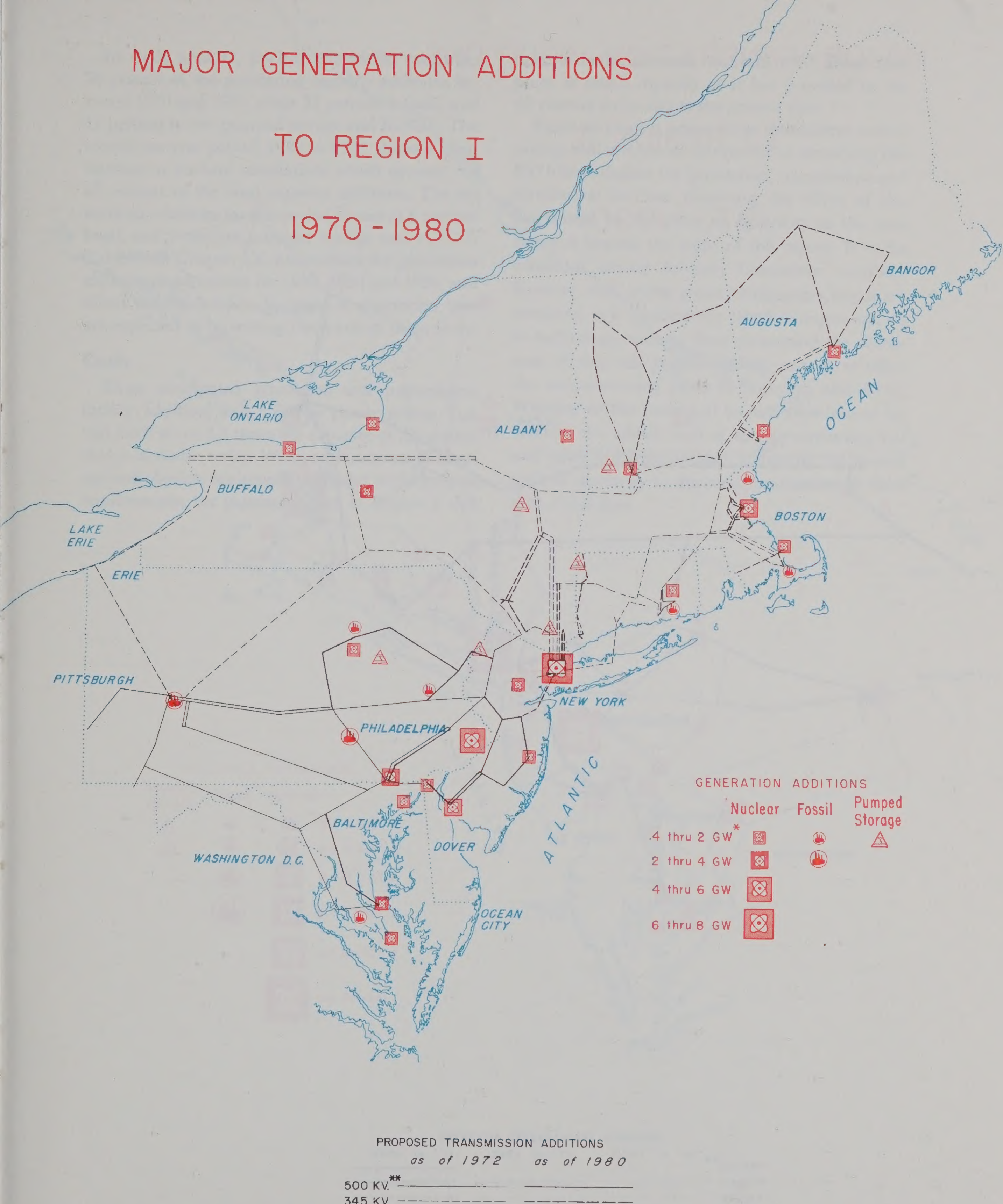
Siting of pumped-storage plants under consideration was limited of necessity by geographical features. In addition to this constraint, pumped-storage plant location is even more greatly influenced by economic considerations of additional transmission facilities, land ownership, and even possible legislative restrictions.

Type Composition by Study Area

The capacity requirements and composition by unit type of each individual power supply area was considered separately, although for discussion purposes it is expedient to group the power supply areas into study areas A, B, and C, as shown on Figure 1. Anticipated unit additions, including those required to offset retirements, from 1970 to 1980 to area A are composed of 59 percent nuclear, 12 percent fossil, and 29 percent pumped-storage, internal combustion, or gas-turbine peaking facilities. During the next ten year interval, the percentage of nuclear generation additions of the total capacity increases rapidly to 82 percent. For this same interval, only 4 percent of the unit additions are fossil, and 14 percent peaking.

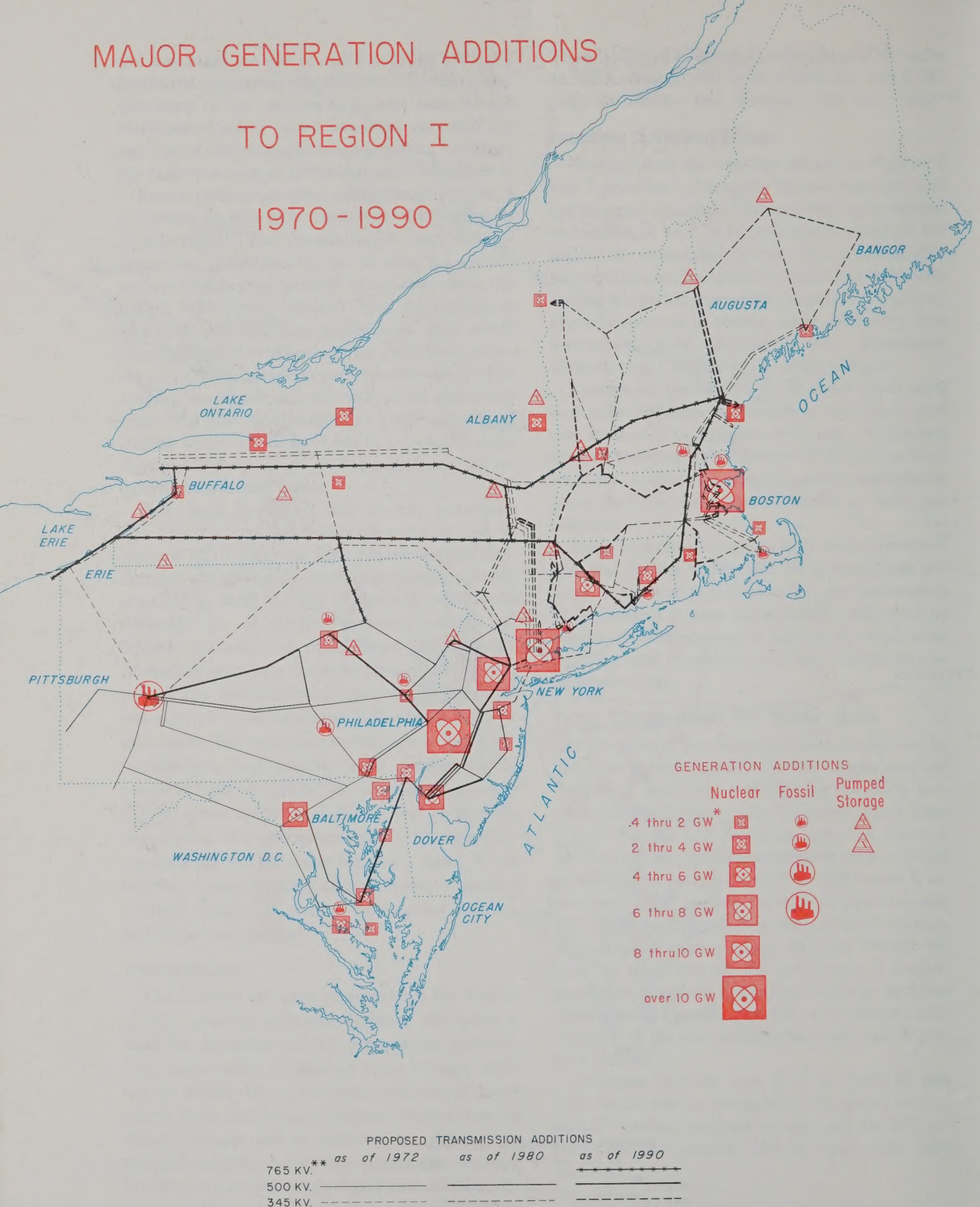
Additions in study area B in the 1970–80 and 1980–90 decade are estimated at 73 percent nuclear and 27 percent pumped storage and IC/GT capacity for both periods, with no fossil steam units included.

[2] Table 17, Chapter VII.



* 1 GW = 1,000,000,000 WATTS
** 1 KV = 1,000 VOLTS

Figure 2
1968



* 1 GW = 1,000,000,000 WATTS

** 1 KV = 1,000 VOLTS

Figure 3
1968

In study area C, nuclear generation comprises 56 percent of the generating capacity additions between 1970 and 1980, while 33 percent is fossil, and 11 percent is new pumped storage and IC/GT. The second ten-year period, 1980 to 1990, shows a great increase in nuclear installations which account for 85 percent of the total capacity additions. The remaining additions for this period consist of 8 percent fossil, and 7 percent pumped storage and IC/GT. Table 18 in Chapter IX, summarizes the generation capacity requirements for 1970, 1980 and 1990, and shows the breakdowns by types of generation that are expected to be serving the loads in those years.

Costs

These anticipated generation and transmission facility additions will create a power system that will have about 3.5 times the capacity of the system that is available today. When replacements of overage and obsolete equipment are added to the growth requirements, the power industry in Region I will need to build, between now and 1990, about four times as much capacity as it has provided in the 80 years of its history to the present time.

Based on current prices, these tremendous undertakings will involve an investment of something like $50 billion dollars for generation, transmission and distribution facilites. Analyzing the effect of this investment on the price of electricity to the consumer is beyond the scope of this report. It is the consensus among Advisory Committee members, however, that, unless present inflationary trends are restained, it is questionable whether improvements in technology, such as those permitting the economies of size, will provide enough savings to offset the ever-increasing costs of materials and labor. Whether or not there will be sufficient leeway for meeting the added costs of solving environmental and other problems without increasing the overall costs of electricity to the consumer, cannot be foreseen at this time.

CHAPTER I

ESTIMATED FUTURE POWER REQUIREMENTS

General

Power system planning, when expanded to regional or national scales, is done on the basis of power supply areas (PSA) established by the Federal Power Commission. These PSA's are generally determined on the basis of the service areas and operating relationships of utility systems comprising them. In turn, power supply areas may be grouped into coordinated study areas (CSA), again determined mainly by the degree of integration and coordination among component power supply areas. Finally, coordinated study areas are combined into power regions involving concepts of coordinated system planning and operation that are area-wide in nature. This pattern is consistent with operations in the area under the cognizance of the northeast Regional Advisory Committee and has been followed in the studies leading to this report.

The estimates of future power requirements discussed in this Chapter, were prepared by the staff of the Federal Power Commission's New York Regional Office, with the assistance and cooperation of an ad hoc industry task force [1] appointed by NERAC for that purpose. Forecasts of total needs represent, to a large degree, a summation of industry expectations for the three study areas in the Region. Following review and revision of initial estimates submitted to NERAC in January 1967, updated projections were approved by the Committee at its Ninth Meeting in May 1968.

Region I, which delineates the area of NERAC responsibility, consists of PSA's 1 through 6, extending east to west from the Maine-New Brunswick boundary to the Ohio-Pennsylvania border in northwestern Pennsylvania and north to south from the Canadian border to Washington, D.C. CSA A (PSA's 1 and 2) is comprised of the six New England states and CSA B consists of PSA's 3 and 4, New York State. CSA C, PSA's 5 and 6, takes in all of the states of Delaware and New Jersey, parts of Maryland, Pennsylvania, and Virginia, and Washington, D.C. Figure 1, in the preceding Summary, shows the geographical extent of Region I by PSA's and CSA's.

Growth in use of electric energy in the United States shows no sign of slackening and added years of record appear to justify raising the sights of previous long-term forecasts, if system planning is not to fail in its purpose of satisfying the future power needs of an expanding population and a vigorous national economy. FPC Region I (Northeast Region) represents a substantial portion of the country's total utility load and has shared, and is continuing to share, in the growth of this vital and dynamic industry. In 1955, Region I energy requirements were 20.6 percent of the total for the contiguous United States, and in 1965 they were 19.3 percent. While the Region's future growth rate may not be as great as in other parts of the country, its load in 1990 is estimated to still comprise over 15 percent of the national total.

Estimates of near future power requirements may differ from values taken from long-range forecasts developed for the up-dated National Power Survey. Any discrepancy should cause no conflict, since the two sets of predictions serve different purposes. Under continuing review by utilities, short-term forecasts are subject to modification as factors that affect use of electric energy change. Such projections are necessary for the formulation of meaningful programs of scheduled maintenance, expansion of generating capacity and transmission networks, and contractual arrangements for power transfer within and between interconnected systems. On the other hand, the main purpose of long-term forecasts is to provide a reasonable evaluation of probable dimensions of power systems of the future and by so doing indicate the general direction that generating unit size, types of generation for specific loads, and EHV levels may be expected to take. These long-range estimates tend to smooth

[1] Appendix E.

out the year-to-year changes in the rate of load growth into general trends over the period under study.

Annual Power Requirements

Total energy requirements in Region I in 1965 amounted to 203.7 billion kilowatt-hours with an associated peak demand of 36.8 million kilowatts and a load factor of 63.1 percent. For 1990, these are estimated at 914.7 billion kilowatt-hours, 164.6 million kilowatts, and 63.4 percent. This represents an energy growth to nearly 4.5 times and an average compound rate of growth of 6.2 percent over the study period.

Ranked by magnitude of energy requirements PSA 5 with 81 billion kilowatt-hours in 1965 is largest, accounting for nearly 40 percent of the region total. This is expected to increase slightly to about 42.5 percent in 1990. PSA 1 with four billion kilowatt-hours in 1965 is smallest with about two percent of the region total from 1955 to 1965. This is estimated to decline to 1.6 percent in 1990. The fastest growing power supply area is expected to be PSA 6 with a 25-year estimated compound rate of growth of 7.3 percent.

On a coordinated study area basis, CSA C (PJM Area) is largest, followed by CSA B (New York) and CSA A (New England) in that order. From 43.7 percent of total region energy in 1965, CSA C is expected to account for more than 47 percent in 1990. CSA's A and B are each estimated to have less than 30 percent of regional energy in 1990.

Table 2 shows past and estimated future annual power requirements (energy, peak, and load factor) in Region I by PSA and CSA. Table 3 shows comparative growth of energy by various indices by PSA's and CSA's. Figure 4 shows past and estimated future annual power requirements for the region and its three component CSA's.

TABLE 2

Region I—Past and Estimated Future Annual Power Requirements by Power Supply Area and Coordinated Study Area

Area	Item	Unit	1950	1955	1960	1965	1970	1975	1980	1985	1990
PSA 1	Energy for Load	Gwh	1,737	2,450	3,079	4,126	5,340	6,920	8,950	11,590	15,000
	Peak Demand	Mw	329	482	565	765	995	1,285	1,655	2,140	2,760
	Load Factor	%	60.3	58.0	62.0	61.6	61.2	61.5	61.6	61.8	62.0
PSA 2	Energy for Load	Gwh	14,932	20,717	27,388	37,656	53,000	73,780	102,050	141,110	194,800
	Peak Demand	Mw	3,279	4,653	5,616	7,821	10,805	14,915	20,445	28,060	38,540
	Load Factor	%	52.0	50.8	55.5	55.0	56.0	56.5	57.0	57.4	57.7
CSA A	Energy for Load	Gwh	16,669	23,167	30,467	41,782	58,340	80,700	111,000	152,700	209,800
	Peak Demand	Mw	3,608	5,134	6,181	8,586	11,800	16,200	22,100	30,200	41,300
	Load Factor	%	52.7	51.5	56.1	55.6	56.4	56.9	57.3	57.7	58.0
PSA 3	Energy for Load	Gwh	17,291	23,085	27,304	36,080	46,100	58,700	74,900	95,700	122,200
	Peak Demand	Mw	2,793	3,987	4,581	6,043	7,730	9,850	12,600	16,150	20,650
	Load Factor	%	70.7	66.1	67.9	68.2	68.1	68.0	67.7	67.6	67.6
PSA 4	Energy for Load	Gwh	15,491	20,827	27,411	36,830	48,700	64,400	85,100	111,700	147,200
	Peak Demand	Mw	3,531	4,549	[1] 5,540	[1] 7,538	[1] 9,930	[1] 12,900	[1] 16,700	[1] 21,800	[1] 28,600
	Load Factor	%	50.1	52.3	56.3	55.8	56.0	57.0	58.0	58.5	58.8
CSA B	Energy for Load	Gwh	32,782	43,912	54,715	72,910	94,800	123,100	160,000	207,400	269,400
	Peak Demand	Mw	6,324	8,536	10,074	13,019	17,060	22,040	28,470	36,970	48,100
	Load Factor	%	59.2	58.7	61.8	63.9	63.4	63.8	64.2	64.0	63.9
PSA 5	Energy for Load	Gwh	31,743	44,057	57,937	81,041	116,640	163,030	218,770	292,920	388,380
	Peak Demand	Mw	6,173	8,719	[1] 10,808	[1] 14,615	[1] 21,070	[1] 29,370	[1] 39,270	[1] 52,410	[1] 69,280
	Load Factor	%	58.7	57.7	61.0	63.3	63.2	63.4	63.6	63.8	64.0
PSA 6	Energy for Load	Gwh	2,365	3,484	5,079	8,002	12,740	18,280	25,490	34,780	47,120
	Peak Demand [2]	Mw	[1] 488	[1] 768	[1] 1,196	[1] 1,874	3,050	[1] 4,340	[1] 6,000	[1] 8,120	[1] 10,910
	Load Factor	%	55.0	51.8	48.3	48.7	47.7	48.1	48.5	48.9	49.3
CSA C	Energy for Load	Gwh	34,108	47,541	63,016	89,043	129,380	181,210	244,260	327,700	435,500
	Peak Demand	Mw	6,646	9,341	[1] 12,044	[1] 16,489	[1] 24,120	[1] 33,710	[1] 45,270	[1] 60,530	[1] 80,190
	Load Factor	%	58.6	58.1	59.8	61.6	61.2	61.4	61.2	61.8	62.0
Reg. I	Energy for Load	Gwh	83,559	114,620	148,198	203,735	282,520	385,110	515,260	687,800	914,700
	Peak Demand	Mw	16,578	23,011	27,517	36,842	51,230	69,590	92,770	123,770	164,640
	Load Factor	%	57.5	56.9	61.3	63.1	63.0	63.1	63.4	63.4	63.4

[1] Summer peak, all others winter.

[2] The most recent Potomac Electric Power Company studies indicate that estimates of peak demands in PSA-6 should be revised upward to 3710 Mw for 1970, 4700 Mw for 1975, 6740 Mw for 1980, 9450 Mw for 1985, and 13,600 Mw for 1990.

NOTE.—1950–65 actual; peak demands coincident as to month, at least. 1970–90 estimated; peak demands assumed true coincident.

TABLE 3

Region I—Comparative Growth of Total Energy Requirements by Power Supply Areas and Coordinated Study Areas

[Index: 1960=100]

	1955	1960*	1965	1970	1975	1980	1985	1990	Five year compound rate of growth in percent						
									55–60	60–65	65–70	70–75	75–80	80–85	85–90
PSA: (Power Supply areas)															
1	80	100	134	173	225	291	376	487	4.7	6.0	5.3	5.3	5.3	5.3	5.3
2	76	100	137	194	269	373	515	711	5.7	6.6	7.1	6.9	6.9	6.7	6.7
3	85	100	132	168	215	274	351	448	3.4	5.7	5.0	5.0	5.0	5.0	5.0
4	76	100	134	178	235	310	408	537	5.7	6.1	5.7	5.7	5.7	5.6	5.6
5	76	100	140	201	281	378	506	670	5.6	6.9	7.6	6.9	6.1	6.0	5.8
6	69	100	158	251	360	502	685	928	7.8	9.5	9.8	7.5	6.9	6.4	6.3
CSA: (Coordinated study area)															
A	76	100	137	191	265	364	501	689	5.6	6.5	6.9	6.7	6.6	6.6	6.6
B	80	100	133	173	225	292	379	492	4.5	5.9	5.4	5.4	5.4	5.3	5.4
C	75	100	141	205	288	388	520	691	5.8	7.2	7.8	7.0	6.1	6.1	5.8
Reg. I	77	100	137	191	260	348	464	617	5.3	6.6	6.7	6.4	6.0	5.9	5.9

NOTE.—CSA A (New England)=PSA's 1 and 2; CSA B (New York)=PSA's 3 and 4; CSA C (PJM Area)=PSA's 5 and 6. *1960 - Energy for load 148,198 GWh
Peak demand 27,517 MW
Load Factor 61.3 %

Seasonal Characteristics

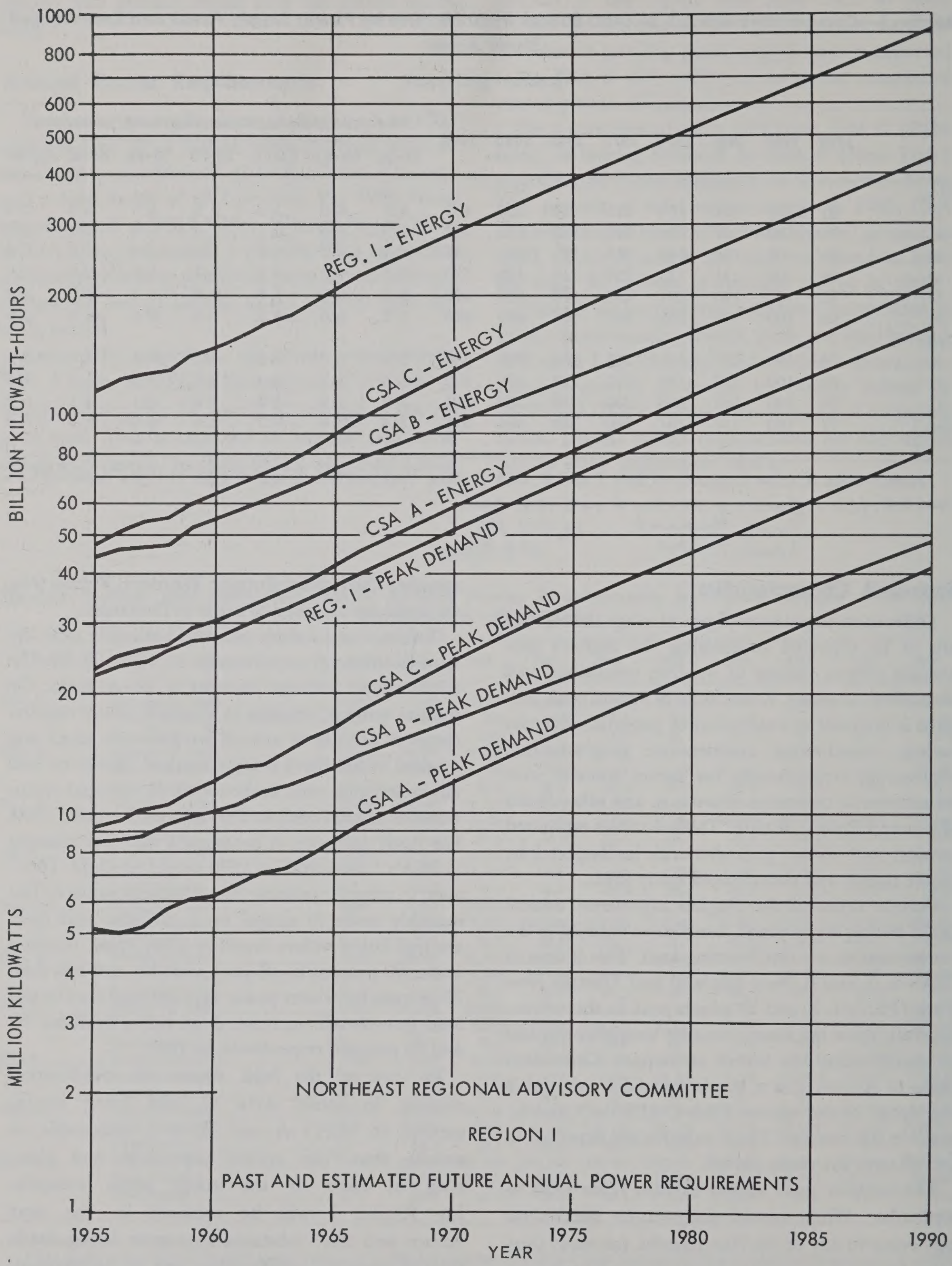
Differences in patterns of power usage in Region I are to be expected considering the region's geographic extent, variety of weather conditions, and diversified economy. Knowledge of system peak patterns is essential to evaluation of potential diversity savings, coordinated maintenance programming, contractual arrangements for power transfer with other systems, or groups of systems, and other facets of power supply planning. Table 4 shows estimated summer and winter peak demands in Region I by power supply and coordinated study areas.

Certain areas of the Region experience annual peaks during the summer, due almost entirely to the warm-weather air conditioning load. This is true of PSA's 4, 5, and 6. New England and Upstate New York (PSA's 1, 2, and 3) which peak in the winter, generally have less severe summer temperatures and air conditioning has less of an impact. Coincident peaks of Region I as a whole and CSA's A and B also occur in the winter. CSA C (PSA's 5 and 6) peaks in the summer. These patterns are expected to prevail over the study period.

The summer peak season extends from June to September. While annual temperature maximums may occur in any of the four months, for study purposes August is assumed to be the summer peak load month. The winter peak season also consists of four months—November through February. Future winter peaks are assumed to occur in December.

Tables 5 and 6 show estimated monthly peak demand and energy requirements for 1970–80–90. The tables reflect average patterns of recent years. On mature systems, changes in monthly power requirements in percent of annual are generally small and gradual unless there is some marked change in load characteristics, such as the switch in reasonal occurrence of annual peak in PSA's 4 and 5 around 1960. For study purposes, it is assumed that any changes in PSA's 1 through 5 to 1990 would be slight. However, in summer peaking PSA 6 current ratios of low monthly peaks to annual on a calendar year basis are well below values found in other areas, running under 60 percent in off-peak months, and less than 70 percent for winter peaks. It is assumed that future load growth will increase these ratios to about 65 and 80 percent, respectively, in 1990.

In view of the high degree of coordination existing in Study Area C, and being implemented in CSA's A and B, it is reasonable to assume that "one system" operation and planning in each of the study areas comprising Region I will be achieved in the near future and that substantial progress being made toward regional coordination will be accelerated. Indicated seasonal diversities given on Table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BILLION KILOWATT-HOURS
MILLION KILOWATTS
REG. I - ENERGY
CSA C - ENERGY
CSA B - ENERGY
CSA A - ENERGY
REG. I - PEAK DEMAND
CSA C - PEAK DEMAND
CSA B - PEAK DEMAND
CSA A - PEAK DEMAND
NORTHEAST REGIONAL ADVISORY COMMITTEE
REGION I
PAST AND ESTIMATED FUTURE ANNUAL POWER REQUIREMENTS
1955
1960
1965
1970
1975
1980
1985
1990
YEAR

Figure 4

TABLE 4

Region I—Estimated Summer and Winter Peak Demands by Power Supply Areas and Coordinated Study Areas (Megawatts)

	1965			1970		1975		1980		1985		1990	
	Summer		Dec.	Aug.	Dec.	Aug.	Dec.	Aug.	Dec.	Aug.	Dec.	Aug.	Dec.
PSA 1	August	669	*765*	865	*995*	1,120	*1,285*	1,440	*1,655*	1,860	*2,140*	2,400	*2,760*
PSA 2	August	6,802	*7,821*	9,370	10,805	12,930	*14,915*	17,725	*20,445*	24,300	*28,060*	33,415	*38,540*
CSA A	August	7,471	*8,586*	10,235	*11,800*	14,050	*16,200*	19,165	*22,100*	26,190	*30,200*	35,815	*41,300*
PSA 3	September	5,419	*6,043*	6,860	*7,730*	8,740	*9,850*	11,180	*12,600*	14,330	*16,150*	18,320	*20,650*
PSA 4	June	*7,538*	6,976	*9,930*	9,330	*12,900*	12,190	*16,700*	15,870	*21,800*	20,820	*28,600*	27,450
CSA B	June	12,905	*13,019*	16,790	*17,060*	21,640	*22,040*	27,880	*28,470*	36,130	*36,970*	46,920	*48,100*
CSA B [1]			13,581		17,660		22,750		29,300		37,950		49,250
PSA 5	August	*14,615*	13,988	*21,070*	20,230	*29,370*	28,200	*39,270*	37,700	*52,410*	50,310	*69,280*	66,510
PSA 6	August	*1,874*	1,249	*3,050*	2,140	*4,340*	3,150	*6,000*	4,500	*8,120*	6,290	*10,910*	8,730
CSA C	August	*16,489*	15,237	*24,120*	22,370	*33,710*	31,350	*45,270*	42,200	*60,530*	56,600	*80,190*	75,240
Reg. I	August	36,728	*36,842*	51,145	*51,230*	69,590	*69,590*	92,315	*92,770*	122,850	*123,770*	162,925	*164,640*
Reg. I [2]			38,094		52,980		71,950		95,840		127,700		169,590
Reg. I [1]			38,656		53,580		72,660		96,670		128,680		170,740

[1] Non-coincident: summation of PSA coincident annual peaks.
[2] Non-coincident: summation of CSA coincident annual peaks.

NOTES.—1. Annual peak demands italicized.
2. Winter peaks in 1965 all occurred in December.
3. Future summer and winter peaks assumed to occur in August and December, respectively.
4. All peaks assumed coincident except as noted above, footnotes 1 and 2.
5. Coincident peaks in 1965 coincident as to month at least.
6. Future coincident peaks assumed true coincident.

4 based on the difference between the sum of the three coordinated study area coincident annual peaks and coincident regional peak, do not for a number of reasons necessarily represent capacity savings capable of practical realization. Estimated diversities shown are small relative to total region peak, being approximately three percent over the 1970–90 study period. They stem from assumed continued differences in season of annual peak occurrence. Changing load characteristics could alter this. Generally, interconnected systems with differing peak patterns effectively coordinate maintenance and reserve requirements to use these differences. Finally, an accurate determination would require more detailed information and an in-depth analysis employing computer techniques. Thus, in effect, lacking the benefit of substantial time zone diversity, it appears unlikely that there would be any future savings in Region I of an amount and dependability that would safely permit a reduction in required capacity.

Principal Load Centers

Among the factors influencing a suitable program of power supply for an area is the geographic dispersion of load. Customers of an electric utility are usually distributed over its service area in varying degrees of concentration. This suggests the useful concept of load centers whose locations and power needs are important considerations in system planning of generating and transmission facilities. They are usually key points on backbone transmission networks for the reception of large blocks of power and may also coincide with power supply centers. Load centers generally conform to concentrations of population, such as metropolitan areas, or groups of communities, and heavy power-consuming industrial complexes. While delineation of load centers involves judgment to a large extent and their power requirements may not be known with exactitude, even approximate coverage is helpful in contributing to a better understanding of the general direction and dimensions of system expansions in the future.

There are 55 identifiable load areas in Region I estimated to have peak demands of at least 100 megawatts in 1970. By 1990, five load centers are expected to peak in excess of 10,000 megawatts, with one (New York City area in PSA 4) over 20,000. Alone, they account for roughly 40 percent of total

TABLE 5

Region I—Past and Estimated Future Monthly Peak Demands (Megawatts)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
					1960							
PSA 1	529	513	503	505	504	482	495	512	505	504	540	565
2	5,199	4,957	4,807	4,779	4,757	4,809	4,687	5,052	5,026	5,043	5,313	5,616
3	4,383	4,128	4,082	4,048	4,086	4,053	4,013	4,116	4,063	4,158	4,346	4,581
4	5,153	4,939	4,717	4,397	4,584	5,177	5,098	5,540	5,300	5,067	5,321	5,493
5	9,898	9,471	9,332	9,035	9,266	10,005	9,761	10,808	10,119	9,583	10,036	10,407
6	791	769	746	939	846	1,054	1,059	1,196	1,136	837	832	855
CSA A	5,728	5,470	5,310	5,284	5,261	5,291	5,182	5,564	5,531	5,547	5,853	6,181
B	9,536	9,067	8,799	8,445	8,670	9,230	9,111	9,656	9,363	9,225	9,667	10,074
C	10,689	10,240	10,078	9,974	10,112	11,059	10,820	12,004	11,255	10,420	10,868	11,262
Reg. I	25,953	24,777	24,187	23,703	24,043	25,580	25,580	27,224	26,149	25,192	26,388	27,517
					1970							
PSA 1	900	880	845	840	825	825	845	865	845	885	930	995
2	9,735	9,410	9,000	8,795	8,850	9,205	9,085	9,370	9,315	9,520	10,105	10,805
3	7,135	6,895	6,725	6,610	6,655	6,715	6,715	6,580	6,810	7,020	7,390	7,730
4	8,640	8,440	8,045	7,795	8,340	9,630	9,780	9,930	9,485	8,590	8,935	9,330
5	18,750	18,590	18,225	17,910	18,645	20,650	20,440	21,070	20,325	18,220	19,700	20,230
6	1,980	1,920	1,860	1,890	2,320	2,975	3,005	3,050	2,850	2,260	2,045	2,140
CSA A	10,635	10,290	9,845	9,635	9,675	10,030	9,930	10,235	10,160	10,405	11,035	11,800
B	15,775	15,335	14,770	14,405	14,995	16,345	16,360	16,790	16,295	15,610	16,325	17,060
C	20,730	20,460	20,085	19,800	20,965	23,625	23,445	24,120	23,175	20,590	21,745	22,370
Reg. I	47,140	46,085	44,700	43,840	45,635	50,000	49,735	51,145	49,630	46,605	49,105	51,230
					1980							
PSA 1	1,495	1,460	1,400	1,400	1,375	1,370	1,405	1,440	1,405	1,470	1,550	1,655
2	18,420	17,810	17,030	16,640	16,745	17,420	17,195	17,725	17,625	18,010	19,115	20,445
3	11,630	11,240	10,960	10,775	10,850	10,950	10,725	11,180	11,100	11,440	12,045	12,600
4	14,530	14,195	12,530	13,110	14,030	16,200	16,450	16,700	15,950	14,445	15,030	15,870
5	34,950	34,560	33,970	33,380	34,755	38,485	38,090	39,270	37,895	34,165	36,720	37,700
6	4,200	3,960	3,780	3,840	4,800	5,850	5,910	6,000	5,610	4,680	4,320	4,500
CSA A	19,915	19,270	18,430	18,040	18,120	18,790	18,600	19,165	19,030	19,480	20,665	22,100
B	26,160	25,435	24,490	23,885	24,880	27,150	27,175	27,880	27,050	25,885	27,075	28,470
C	39,150	38,520	37,750	37,220	39,555	44,335	44,000	45,270	43,505	38,845	41,040	42,200
Reg. I	85,225	83,225	80,670	79,145	82,555	90,275	89,775	92,315	89,585	84,210	88,780	92,770
					1990							
PSA 1	2,490	2,435	2,335	2,330	2,295	2,285	2,340	2,400	2,345	2,450	2,585	2,760
2	34,725	33,570	32,105	31,370	31,565	32,835	32,410	33,415	33,220	33,955	36,035	38,540
3	19,060	18,420	17,965	17,655	17,780	17,945	17,575	18,320	18,195	18,750	19,740	20,650
4	24,880	24,310	23,165	22,450	24,025	27,740	28,170	28,600	27,315	24,740	25,740	27,450
5	61,660	60,965	59,930	58,890	61,315	67,895	67,200	69,280	66,855	60,275	64,775	66,510
6	8,185	7,530	7,090	7,310	9,165	10,635	10,745	10,910	10,200	8,945	8,400	8,730
CSA A	37,215	36,005	34,440	33,700	33,860	35,120	34,750	35,815	35,565	36,405	38,620	41,300
B	43,940	42,730	41,130	40,105	41,805	45,685	45,745	46,920	45,510	43,490	45,480	48,100
C	69,845	68,495	67,020	66,200	70,480	78,530	77,945	80,190	77,055	69,220	73,175	75,240
Reg. I	151,000	147,230	142,590	140,005	146,145	159,335	158,440	162,925	158,130	149,115	157,275	164,640

load in the Region. Table 7 lists the 55 major load areas, by coordinated study area, with their estimated 1970–80–90 peaks. The demands represent an allocation of estimated coincident annual power supply area peaks, assuming no diversity among centers. Coverage on a power supply area basis ranges from a little under 75 percent to about 94 percent for PSA 4 and 100 percent for PSA 6. The shaded areas on Figure 5 indicate general locations of load concentrations. These correspond, for the most part to population centers and areas of industrial and economic activity. Some sections of the Region, such as Vermont, all but the extreme southern portion of New Hampshire, and a large

TABLE 6

Region I—Past and Estimated Future Monthly Energy Requirements (Gigawatt-hours)

	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Annual
						1960							
PSA 1	268	251	265	251	256	241	243	264	243	259	260	277	3,078
2	2,396	2,250	2,391	2,173	2,173	2,190	2,087	2,317	2,214	2,320	2,338	2,539	27,388
3	2,391	2,252	2,369	2,252	2,260	2,202	2,143	2,263	2,205	2,282	2,266	2,419	27,304
4	2,330	2,173	2,347	2,102	2,144	2,280	2,304	2,476	2,241	2,265	2,255	2,494	27,411
5	5,006	4,714	5,028	4,549	4,624	4,782	4,702	5,180	4,701	4,790	4,751	5,109	57,936
6	388	364	391	373	389	456	493	549	454	406	390	425	5,078
CSA A	2,664	2,501	2,656	2,424	2,429	2,431	2,330	2,581	2,457	2,579	2,598	2,816	30,466
B	4,721	4,425	4,716	4,354	40,404	4,482	4,447	4,739	4,446	4,547	4,521	4,913	54,715
C	5,394	5,078	5,419	4,922	5,013	5,238	5,195	5,729	5,155	5,196	5,141	5,534	63,014
Reg. I	12,779	12,004	12,791	11,700	11,846	12,151	11,972	13,049	12,058	12,322	12,260	13,263	148,195
						1970							
PSA 1	465	420	450	435	435	415	425	460	425	460	460	490	5,340
2	4,665	4,240	4,505	4,185	4,185	4,240	4,185	4,400	4,295	4,560	4,560	4,980	53,000
3	4,010	3,690	3,920	3,690	3,735	3,690	3,690	3,825	3,725	3,965	3,965	4,195	46,100
4	4,090	3,700	3,995	3,700	3,845	4,140	4,430	4,430	4,045	4,045	3,945	4,335	48,700
5	9,915	8,980	9,680	9,100	9,330	9,680	10,030	10,265	9,680	9,800	9,680	10,500	116,640
6	970	865	930	890	1,020	1,195	1,375	1,340	1,135	1,005	970	1,045	12,740
CSA A	5,130	4,660	4,955	4,620	4,620	4,655	4,610	4,860	4,720	5,020	5,020	5,470	58,340
B	8,100	7,390	7,915	7,390	7,580	7,830	8,120	8,255	7,770	8,010	7,910	8,530	94,800
C	10,885	9,845	10,610	9,990	10,350	10,875	11,405	11,605	10,815	10,805	10,650	11,545	129,380
Reg. I	24,115	21,895	23,480	22,000	22,550	23,360	24,135	24,720	23,305	23,835	23,580	25,545	282,520
						1980							
PSA 1	780	705	750	725	725	700	715	770	715	770	770	825	8,950
2	8,980	8,165	8,675	8,060	8,060	8,165	8,065	8,470	8,265	8,775	8,775	9,595	102,050
3	6,515	5,900	6,365	5,990	6,070	5,995	5,995	6,215	6,070	6,440	6,440	6,815	74,900
4	7,150	6,470	6,980	6,470	6,725	7,235	7,740	7,740	7,060	7,060	6,895	7,575	85,100
5	18,595	16,845	18,160	17,060	17,500	18,160	18,815	19,250	18,160	18,375	18,160	19,690	218,770
6	1,935	1,735	1,860	1,785	2,040	2,395	2,755	2,675	2,270	2,015	1,935	2,090	25,490
CSA A	9,760	8,870	9,425	8,785	8,785	8,865	8,780	9,240	8,980	9,545	9,545	10,420	111,000
B	13,665	12,460	13,345	12,460	12,795	13,230	13,735	13,955	13,130	13,500	12,225	14,390	160,000
C	20,530	18,580	20,020	18,845	19,540	20,555	21,570	21,925	20,430	20,390	20,095	21,780	244,260
Reg. I	43,955	39,910	42,790	40,090	41,120	42,650	44,085	45,120	42,540	43,435	42,975	46,590	515,260
						1990							
PSA 1	1,305	1,185	1,260	1,215	1,215	1,170	1,200	1,290	1,200	1,290	1,290	1,380	15,000
2	17,145	15,585	16,560	15,390	15,390	15,585	15,390	16,165	15,780	16,750	16,750	18,310	194,800
3	10,630	9,775	10,385	9,775	9,900	9,775	9,775	10,145	9,900	10,510	10,510	11,120	122,200
4	12,365	11,185	12,070	11,185	11,630	12,510	12,295	12,295	12,220	12,220	11,925	12,100	147,200
5	33,010	29,910	32,235	30,295	31,070	32,235	33,400	34,175	32,235	32,625	32,235	34,955	388,380
6	3,580	3,205	3,440	3,300	3,770	4,430	5,090	4,945	4,195	3,720	3,580	3,865	47,120
CSA A	18,450	16,770	17,820	16,605	16,605	16,755	16,590	17,455	16,980	18,040	18,040	19,690	209,800
B	22,995	20,960	22,455	20,960	21,530	22,285	23,170	23,540	22,120	22,730	22,435	24,220	269,400
C	36,590	33,115	35,675	33,595	34,840	36,665	38,490	39,120	36,430	36,345	35,815	38,820	435,500
Reg. I	78,035	70,845	75,950	71,160	72,975	75,705	78,250	80,115	75,530	77,115	76,290	82,730	914,700

part of Maine are devoid of load centers that meet the size criterion suggested in this discussion.

Classified Sales

The utility load is comprised of the demands of the various customers served. Differences in characteristics of their requirements permit segregation of customers into distinct categories. Such classification facilitates the analysis and utilization of power requirements and supply data. Further, consideration of power needs on a class-of-service basis, taking into account all the factors peculiar to a particular category, helps to identify the overall picture of an area's industrial and commercial development, the

state of its economy, and the probable direction of future growth.

Major categories of use may be broadly defined as rural and residential, commercial, industrial, and all other. Usually of relatively small magnitude power-wise, the last named would include such uses as street lighting, water pumping, schools, other municipal services, etc. Rural consumption includes electric energy used in agriculture and depends on the type of farm and the availability of labor saving devices and the extent to which they are employed. Residential consumption is a function of population, average use per customer and appliance saturation. For the most part, the commercial category encompasses those utility customers serving directly the functional and recreational needs of people in their day-to-day lives. It includes such establishments as retail stores, filling stations, dry cleaners, theatres, shopping centers, etc. The industrial segment of load includes the large power consumers and may cover

TABLE 7

Region I—Estimated Peak Demands of Principal Load Areas [1] (Megawatts)

Load Area	1970	1980	1990
CSA A—New England:			
Boston, Mass.	2, 840	5, 380	10, 140
Providence, R.I.	760	1, 430	2, 700
Hartford, Conn.	700	1, 330	2, 500
Springfield-Holyoke, Mass.	430	820	1, 540
Fall River-New Bedford, Mass.	420	800	1, 500
New Haven, Conn.	400	760	1, 430
Lawrence-Lowell, Mass.	390	740	1, 390
Stamford-Norwalk, Conn.	380	720	1, 350
Bridgeport, Conn.	380	710	1, 340
Waterbury, Conn.	270	510	960
Worcester, Mass.	260	490	920
Augusta, Me.	230	390	660
Portland, Me.	230	390	660
Middletown-Meridan, Conn.	220	410	770
Fitchburg-Leominster, Mass.	210	390	730
Brockton, Mass.	200	390	730
Manchester-Nashua, N.H.	200	380	720
Bangor, Me.	150	240	410
New London, Conn.	140	270	500
Willimantic, Conn.	140	260	500
Rumford, Me.	110	190	310
Total Load Areas [2]	9, 060	17, 000	31, 760
Total Study Area [2]	11, 800	22, 100	41, 300

See footnotes at end of table.

TABLE 7—Continued

Region I—Estimated Peak Demands of Principal Load Areas [1] (Megawatts)—Continued

Load Area	1970	1980	1990
CSA B—New York:			
New York, N.Y.	7, 350	12, 360	21, 160
Buffalo-Niagara	2, 180	3, 550	5, 820
Long Island	1, 910	3, 210	5, 490
Massena, N.Y.	800	1, 310	2, 150
Rochester	700	1, 130	1, 860
Syracuse	430	710	1, 160
Albany	420	690	1, 140
Binghamton	240	390	640
Elmira-Corning	190	320	520
Utica-Rome	180	290	470
Geneva-Auburn	170	280	450
Jamestown	120	200	330
Ithaca	110	180	290
Amsterdam-Rotterdam	110	180	290
Newburgh-Poughkeepsie	110	180	320
Plattsburgh	100	150	240
Total Load Areas [3]	15, 120	25, 130	42, 330
Total Study Area [4]	17, 660	29, 300	49, 250
CSA C—PJM Area:			
Philadelphia, Pa.	4, 210	7, 850	13, 860
N.E. New Jersey	3, 140	5, 850	10, 320
Washington, D.C.	3, 050	6, 000	10, 910
Baltimore, Md.	2, 650	4, 950	8, 730
New Brunswick-Perth Amboy, N.J.	1, 140	2, 120	3, 740
Allentown-Bethlehem-Easton, Pa.	990	1, 850	3, 260
Camden, N.J.	840	1, 570	2, 770
Lancaster-York	740	1, 370	2, 420
Wilmington, Del.	570	1, 060	1, 870
Scranton–Wilkes-Barre, Pa.	440	820	1, 450
Reading, Pa.	380	710	1, 250
Harrisburg, Pa.	380	710	1, 250
Altoona-Johnstown, Pa.	360	670	1, 180
Trenton, N.J.	360	670	1, 180
Erie, Pa.	340	630	1, 110
Vineland, N.J.	230	430	760
Atlantic City, N.J.	210	390	690
Lebanon, Pa.	210	390	690
Total Load Areas [5]	20, 240	38, 040	67, 440
Total Study Area [5]	24, 120	45, 270	80, 190
Region I:			
Total Load Areas [3]	44, 420	80, 170	141, 530
Total Region [6]	53, 580	96, 670	170, 740

[1] Based on allocation of estimated coincident annual power supply area peaks assuming no diversity.

[2] Winter peak.

[3] Non-coincident.

[4] Non-coincident. Sum of PSA 3 (winter) and PSA 4 (summer) peaks.

[5] Summer peak.

[6] Non-coincident. Sum of study area peaks shown.

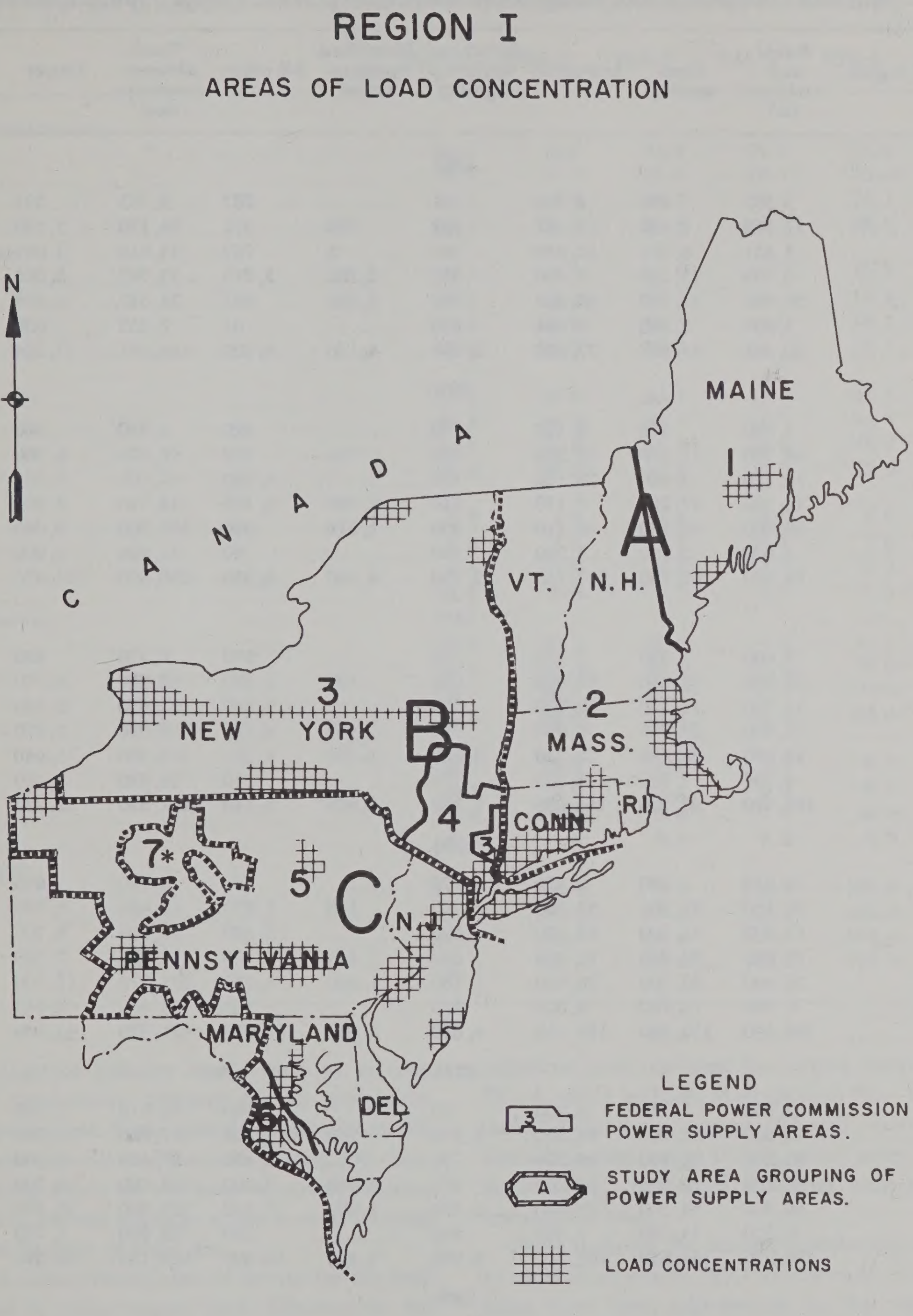

Figure 5

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TABLE 8

Region I—Past and Estimated Future Energy Requirements by Class of Service (Million Kilowatt-Hours)

PSA and region	Rural and residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total ultimate consumption	Losses	Energy for load
1965									
1	1, 155	492	1, 760	41	....	287	3, 735	391	4, 126
2	11, 712	7, 488	13, 367	522	126	911	34, 126	3, 530	37, 656
3	7, 551	6, 004	18, 349	343	3	769	33, 019	3, 061	36, 080
4	9, 519	13, 232	5, 466	553	2, 782	2, 210	33, 762	3, 068	36, 830
5	20, 833	14, 188	36, 898	702	1, 239	687	74, 547	6, 494	81, 041
6	1, 894	3, 263	2, 034	100	....	61	7, 352	650	8, 002
Total	52, 664	44, 667	77, 874	2, 261	4, 150	4, 925	186, 541	17, 194	203, 735
1970									
1	1, 520	670	2, 180	50	....	420	4, 840	500	5, 340
2	16, 700	11, 200	18, 330	700	130	960	48, 020	4, 980	53, 000
3	10, 100	8, 200	22, 160	420	....	1, 120	42, 000	4, 100	46, 100
4	13, 700	17, 200	7, 170	640	2, 900	3, 100	44, 710	3, 990	48, 700
5	29, 800	20, 280	54, 110	850	1, 310	950	107, 300	9, 340	176, 640
6	3, 080	5, 230	3, 200	130	....	80	11, 720	1, 020	12, 740
Total	74, 900	62, 780	107, 150	2, 790	4, 340	6, 630	258, 590	23, 930	282, 520
1975									
1	2, 000	920	2, 720	60	....	570	6, 270	650	6, 920
2	23, 300	16, 240	25, 000	850	120	1, 340	66, 850	6, 930	73, 780
3	13, 300	11, 150	26, 850	510	....	1, 640	53, 450	5, 150	58, 700
4	18, 800	22, 700	9, 460	740	3, 160	4, 150	59, 010	5, 390	64, 400
5	42, 070	28, 520	75, 710	1, 000	1, 390	1, 300	149, 990	13, 040	163, 030
6	4, 520	7, 670	4, 350	170	....	110	16, 820	1, 460	18, 280
Total	103, 990	87, 200	144, 090	3, 330	4, 670	9, 110	352, 390	32, 720	385, 110
1980									
1	2, 610	1, 280	3, 370	70	....	790	8, 120	830	8, 950
2	32, 500	23, 380	33, 500	1, 100	110	1, 870	92, 460	9, 590	102, 050
3	17, 500	15, 200	32, 500	620	....	2, 380	68, 200	6, 700	74, 900
4	25, 800	29, 900	12, 430	850	3, 440	5, 400	77, 820	7, 280	85, 100
5	58, 500	39, 500	98, 850	1, 180	1, 490	1, 750	201, 270	17, 500	218, 770
6	6, 580	10, 700	5, 800	230	....	140	23, 450	2, 040	25, 490
Total	143, 490	119, 960	186, 450	4, 050	5, 040	12, 330	471, 320	43, 940	515, 260
1985									
1	3, 380	1, 750	4, 200	80	....	1, 100	10, 510	1, 080	11, 590
2	45, 200	33, 700	44, 800	1, 450	100	2, 600	127, 850	13, 260	141, 110
3	23, 000	20, 700	39, 200	750	....	3, 450	87, 100	8, 600	95, 700
4	35, 100	39, 300	16, 200	960	3, 740	6, 900	102, 200	9, 500	111, 700
5	80, 300	54, 500	129, 380	1, 370	1, 600	2, 350	269, 500	23, 420	292, 920
6	9, 250	14, 700	7, 560	310	....	180	32, 000	2, 780	34, 780
Total	196, 230	164, 650	241, 340	4, 920	5, 440	16, 580	629, 160	58, 640	687, 800
1990									
1	4, 360	2, 410	5, 260	90	....	1, 500	13, 620	1, 380	15, 000
2	62, 750	48, 300	59, 850	1, 900	100	3, 600	176, 500	18, 300	194, 800
3	30, 000	28, 000	47, 400	940	....	5, 000	111, 340	10, 860	122, 200
4	48, 200	51, 600	21, 000	1, 120	4, 020	8, 660	134, 600	12, 600	147, 200
5	110, 000	74, 200	166, 650	1, 580	1, 720	3, 750	357, 300	31, 080	388, 380
6	13, 000	19, 950	9, 780	400	....	220	43, 350	3, 770	47, 120
Total	268, 310	224, 460	309, 940	6, 030	5, 840	22, 130	836, 710	77, 990	914, 700

TABLE 9

Region I—Percent Distribution of Total Deliveries to Ultimate Consumers by Power Supply Areas

	PSA–1	PSA–2	PSA–3	PSA–4	PSA–5	PSA–6
Rural and Residential:						
1960	30. 6	30. 8	21. 2	24. 8	25. 6	23. 6
1970	28. 5	31. 5	22. 0	28. 2	25. 6	24. 2
1980	29. 2	31. 9	22. 5	30. 5	26. 7	25. 8
1990	29. 1	32. 2	24. 5	32. 7	28. 3	27. 6
Communities:						
1960	10. 7	18. 3	13. 6	35. 7	16. 7	53. 4
1970	12. 5	21. 1	17. 3	35. 3	17. 4	41. 1
1980	14. 3	22. 9	18. 5	35. 0	18. 1	42. 0
1990	16. 1	24. 8	22. 9	35. 1	19. 1	42. 3
Industrial:						
1960	41. 3	36. 6	50. 1	13. 7	45. 1	11. 2
1970	40. 8	34. 6	48. 5	14. 7	46. 4	25. 1
1980	37. 6	32. 8	46. 8	14. 6	45. 2	22. 8
1990	35. 0	30. 7	38. 8	14. 3	42. 9	20. 8
All Other:						
1960	7. 3	4. 4	5. 4	17. 0	3. 9	3. 1
1970	8. 8	3. 4	3. 1	13. 6	2. 6	1. 6
1980	9. 6	3. 0	3. 2	11. 3	2. 0	1. 4
1990	10. 6	2. 9	4. 9	9. 4	1. 7	1. 3
Total Deliveries:						
1960	89. 9	90. 1	90. 3	91. 2	91. 3	91. 3
1970	90. 6	90. 6	90. 9	91. 8	92. 0	92. 0
1980	90. 7	90. 6	91. 0	91. 4	92. 0	92. 0
1990	90. 8	90. 6	91. 1	91. 5	92. 0	92. 0
Losses:						
1960	10. 1	9. 9	9. 7	8. 8	8. 7	8. 7
1970	9. 4	9. 4	9. 1	8. 2	8. 0	8. 0
1980	9. 3	9. 4	9. 0	8. 6	8. 0	8. 0
1990	9. 2	9. 4	8. 9	8. 5	8. 0	8. 0
Total Energy:						
1960	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0
1970	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0
1980	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0
1990	100. 0	100. 0	100. 0	100. 0	100. 0	100. 0

a wide range of industry types, such as mining, chemical production, primary metals processing, manufacturing, etc. Some systems do not distinguish between commercial and industrial types, but characterize them solely on the basis of power requirements. This practice may also apply to some farming operations because of their size.

Table 8 shows sales by class of service for the total region and by power supply area. Regionwide, the industrial load constitutes the largest category of use, accounting for 38 percent of 204 billion kilowatt-hours total energy in 1965. The industrial load is expected to decline to about 34 percent of the total in 1990 in keeping with the past trend. In four of the six power supply areas comprising Region I, industrial sales represent the largest component. In PSA 4, which includes Metropolitan New York, they ranked behind the commercial and rural and residential classes; and in PSA 6, which takes in Washington, D.C., industrial deliveries were second to commercial sales.

Table 9 shows the percent distribution of energy by class of service to 1990. Historically, the greatest gains have been experienced in the commercial, rural, and residential categories. In PSA's 1, 2, 3, and 5 in which industrial sales exceeded 35 percent of total energy requirements in 1960, this class of use is expected to decrease. PSA's 4 and 6, which had industrial deliveries under 15 percent of total energy in 1960, are estimated to have industrial use

increases, a modest one for PSA–4, and a more substantial gain in PSA–6.

In this discussion, farm and non-farm residential needs have been lumped together. Of the total rural and residential energy of 52.7 billion kilowatt-hours in the region in 1965, non-farm use is estimated at 51 billion kilowatt-hours, nearly 97 percent of the total. While the downward trend in number of farms is expected to continue, increases in size of farms and average annual use are estimated to yield a total farm use in Region I of 3.2 billion kilowatt-hours in 1990, as against 1.7 billion in 1965. However, growth in the non-farm residential category is expected to be such that the farm component of total rural and residential will decline percentagewise to a little more than one percent by 1990.

Except for PSA's 4 and 6, where commercial sales already account for a large portion of total energy (35–40 percent in 1965), this category is expected to register modest to substantial gains. PSA 6 takes in Washington, D.C., where a major portion of energy sales to the U.S. Government are classified as commercial. By 1990, commercial sales in percent of total energy in PSA's 1, 2, 3, and 5 are estimated to range from 16 to 25 percent. Average use per customer in PSA's 2, 3, 4, and 5 ranged from about 21,000 to 30,000 kilowatt-hours in 1965 and is estimated at 88,000 to 105,000 in 1990. In PSA 1 average use was a little more than 12,000 kilowatt-hours in 1965 and is expected to be in the order of 42,000 by 1990. Because of the large government load in PSA 6, comparison with the other areas is not too meaningful.

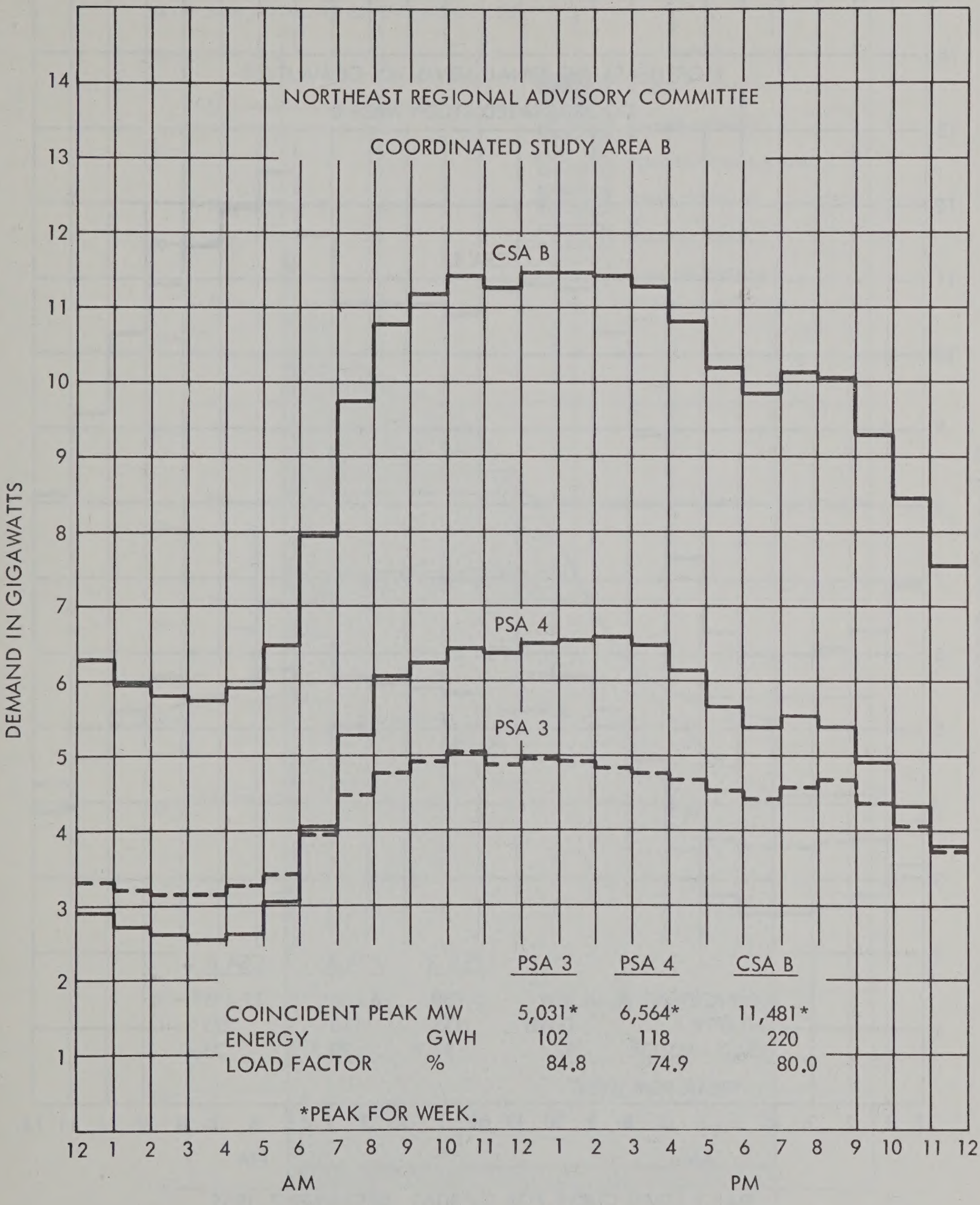
Utility Load Curves

Utility loads vary with time in patterns determined by the nature and degree of the human and economic activity peculiar to the area concerned. A load curve showing demands plotted against time is essential to any meaningful system analysis. Not only are such curves revealing with respect to system characteristics, but they contribute to a clearer understanding of capacity utilization in serving the load. Figures 6 and 7 illustrate actual integrated hourly load curves for the peak day for selected weeks in August and December for PSA's 3 and 4, separately and combined. These areas were selected because they represent previously separate pools that now comprise the New York Power Pool, and they have different load characteristics. PSA 3 peaks in the winter and PSA 4 in the summer. PSA 3 has a large industrial load and a high load factor relative to PSA 4. The following tabulation gives load characteristics for the week containing the days plotted:

	August 1965			December 1965		
	PSA 3	PSA 4	CSA B	PSA 3	PSA 4	CSA B
Coincident Peak-Mw	5, 031	6, 564	11, 481	5, 807	6, 666	12, 466
Energy-Gwh	667	740	1, 407	743	734	1, 477
Load Factor %	78	67	72	76	65	70
Ratio: $\frac{\text{Max. Demand}}{\text{Min. Demand}}$	1. 8	2. 9	2. 3	1. 9	2. 9	2. 4

Examination of the curves indicates that for these particular days, variation in demand is less pronounced for PSA 3 than PSA 4, reflecting in part the former area's higher load factor. This is shown by the ratios of daily maximum to minimum demand of 1.6 for PSA 3 and 2.6 for PSA 4 in August and 1.7 and 2.6, respectively, in December. The daily ratios are not as large as corresponding weekly ones shown above because of the effect of the low demand Saturday and Sunday period. The curves also demonstrate the effect of seasons on the peak. In December, with early darkness, the combined peak is sharp and of short duration. In August, for the day shown, high demands are sustained over a long period.

Another useful device widely employed in system analyses is the load duration curve, which shows demands for the period desired in order of descending magnitude. Perhaps the most commonly used is the weekly load duration curve. Most system operations are keyed to a weekly cycle, such as maintenance scheduling as it affects thermal capacity available for load, hydroelectric generation, both conventional and pumped storage, and continuing review of weekly and daily load forecast. While components of a system, or area power



DAILY LOAD CURVE FOR FRIDAY, AUGUST 6, 1965

Figure 6

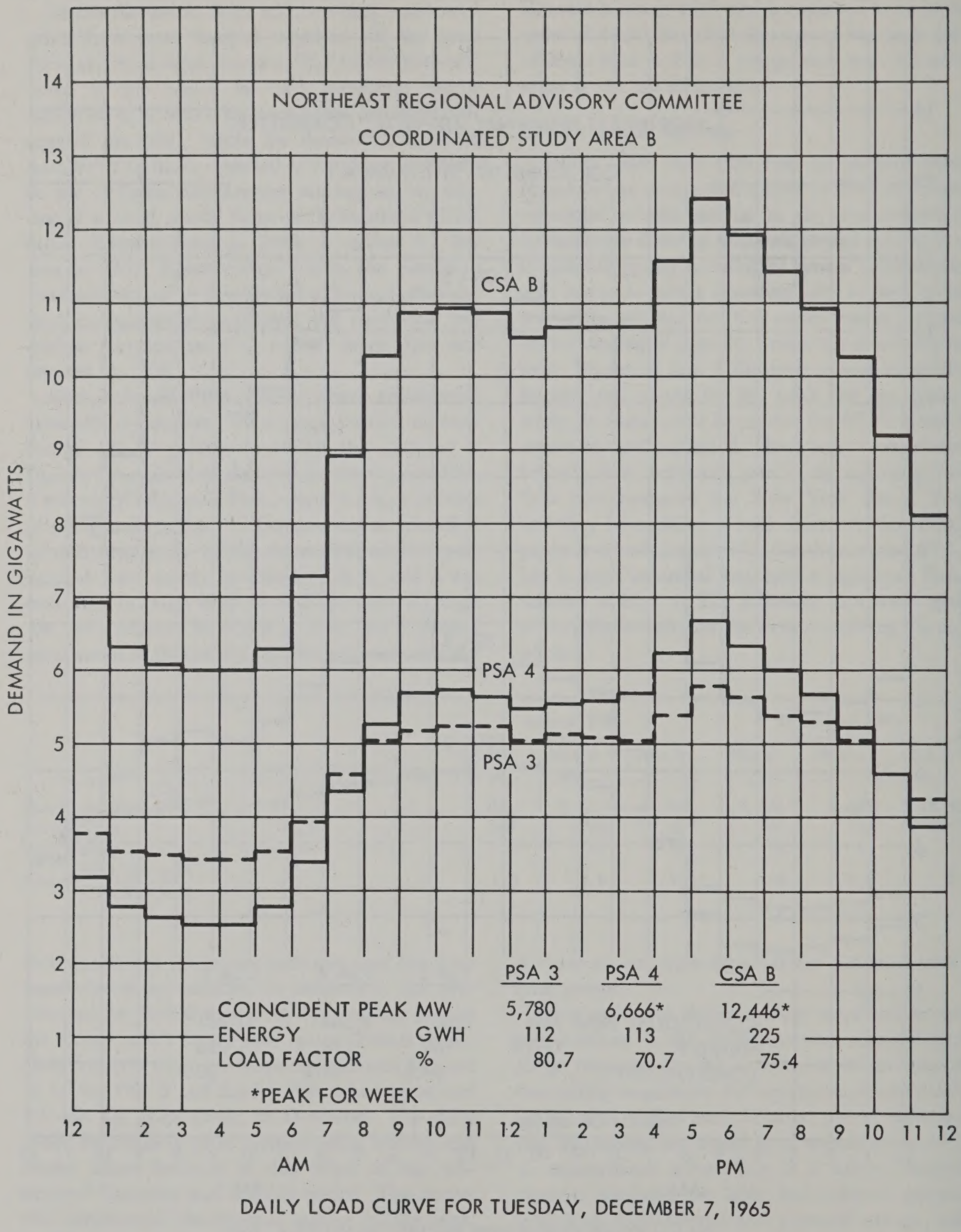

NORTHEAST REGIONAL ADVISORY COMMITTEE
COORDINATED STUDY AREA B
CSA B
PSA 4
PSA 3
DEMAND IN GIGAWATTS
14
13
12
11
10
9
8
7
6
5
4
3
2
1
PSA 3 PSA 4 CSA B
COINCIDENT PEAK MW 5,780 6,666* 12,446*
ENERGY GWH 112 113 225
LOAD FACTOR % 80.7 70.7 75.4
*PEAK FOR WEEK
12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12
AM
PM
DAILY LOAD CURVE FOR TUESDAY, DECEMBER 7, 1965

Figure 7

NORTHEAST REGIONAL ADVISORY COMMITTEE
COORDINATED STUDY AREA B
TYPICAL LOADING OF ESTIMATED 1990 PEAK WEEK LOAD DURATION CURVE

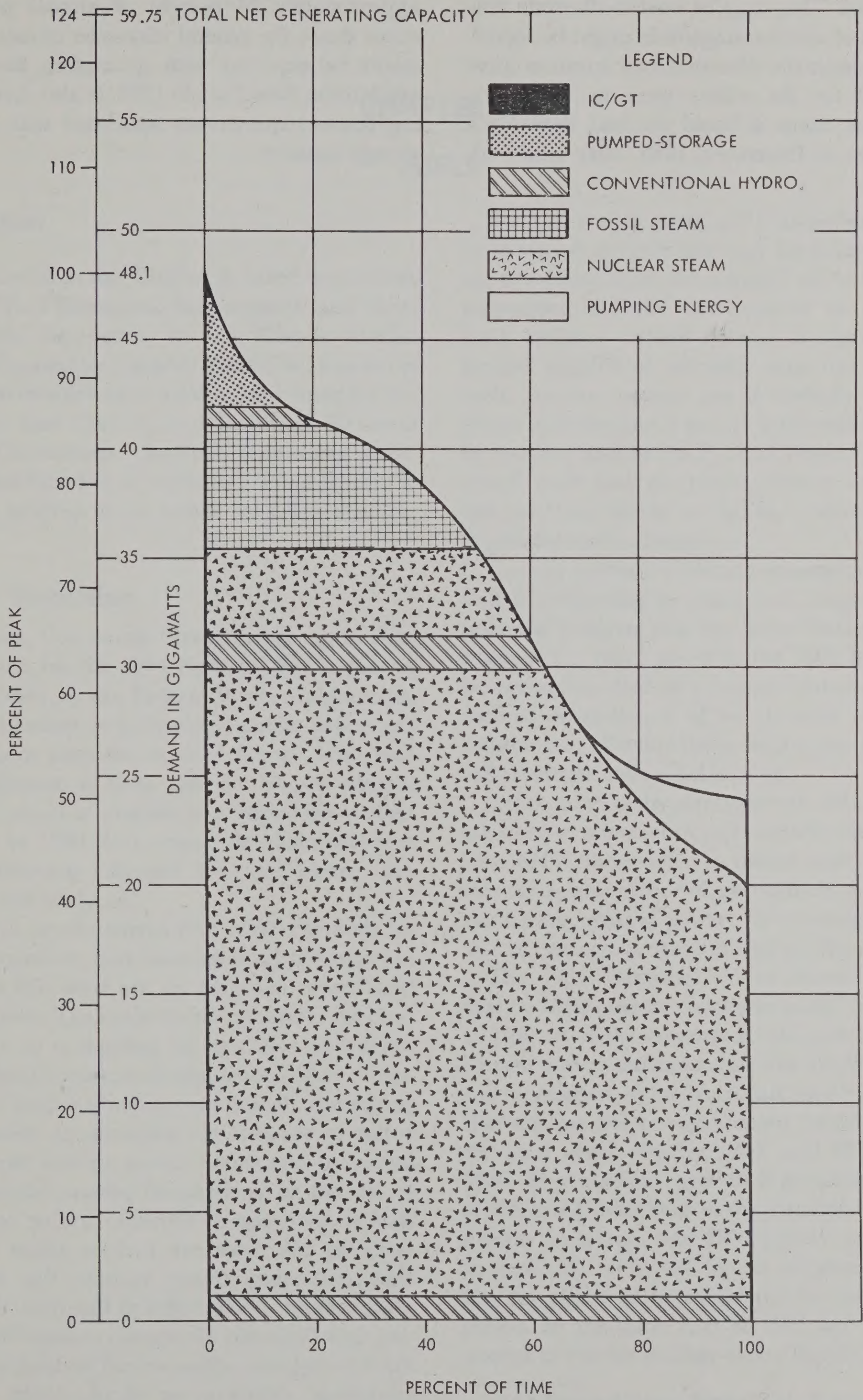


Figure 8

supply, may be shown on an hourly load curve, they are more easily and descriptively positioned on a duration curve in accordance with their operating characteristics. They may be used to illustrate how future loads of various magnitude might be served.

Figure 8 shows the estimated load duration curve for CSA B for the winter peak in 1990. The shape of the curve is based on load data for a selected week in December, 1965, after minor adjustments to reflect anticipated changes in load patterns to 1990. Also indicated is the total net available power supply assuming required reserves of approximately 24 percent of annual peak. The curve shows the general allocation of capacity that might be expected with generation likely to be available in New York in 1990. It also shows pumping power requirements associated with pumped-storage capacity.

CHAPTER II

FUELS

Introduction

The material in this Chapter is based on a report entitled, "Fuel Resources, Requirements and Costs for Electric Generation in the Eastern United States," prepared by a special Fossil Fuel Resources Committee established to make a joint study for the Northeast, East Central, and Southeast Regional Advisory Committees. The Fuels Committee report is being published as a separate document, and it should be referred to for details not covered in this Chapter.

General Discussion

The Fuels Committee report brings up to date studies made for the 1964 National Power Survey (Survey 1964) of the Federal Power Commission, reflecting changes in technology, public policy and energy trends since the original Survey, with particular reference to fuels used for electric generation. The period of analysis is extended by another ten years, to 1990. Intervening developments that have significantly changed the fuel picture are identified and analyzed.

Two such developments with respect to fuels for electric generation that have assumed preeminence in the last few years are air pollution control and nuclear power. The nation's concern about the need for cleaner air is resulting in legislation at federal, state and local levels mandating, among other things, the use of fuels having a progressively decreasing sulfur content to minimize the emission of sulfur dioxide from electric power plants and industrial and residential heating installations, or the use of processes to reduce sulfurous emissions when fuels of higher sulfur content are used. Air pollution abatement will increase power generation costs which ultimately will be reflected in consumer rates, and will necessitate changes in historical fuel patterns as the demand for low-sulfur coal and oil tends to place undue strain on available short-term supplies.

For the longer term, 1971 and thereafter, the problems of air pollution may be reduced through the development of commercial fuel desulfurization techniques and the development of commercial stack emission control systems to supplement the limited supplies of naturally occurring low sulfur fuels. Because natural gas is virtually sulfur-free, its use as boiler fuel is receiving increasing attention by industry and by the Federal Power Commission which must find the public interest in balancing the need for cleaner air against conservation of a depletable national resource.

Nuclear power for electric generation has made and is continuing to make such impressive technological progress that the projections of nuclear's share of the fuel market in the 1964 Survey must be revised upward to a marked extent. The commercial development of fast breeder reactors will substantially alleviate the present factor of economically limited nuclear fuel reserves.

Other noteworthy developments include the rising trend in minemouth and midpoint electric plants with EHV transmission to distant load centers; the increasing acceptance of gas turbines and pumped storage for peaking power; "total energy" systems; and technologic progress in coal gasification.

The 1964 "National Power Survey" indicated that by 1980 nuclear capability would be supplying 10 percent of the Nation's KWH generation.[1] Our current survey indicates that this 10 percent point will be reached, in the Northeast region in 1969 and that nuclear power will account for 60 percent of the total generation by 1980, and 82 percent by 1990. This predicted growth is primarily the result of estimated reductions in the installed cost of large nuclear units from over $200 per Kw prior to 1964 to generally estimated figures of about $150 per Kw for plants to be completed in the 1967–1970 period. In the latter part of 1967 and early 1968, quoted prices for nuclear steam supply systems in-

[1] 1964 National Power Survey, Vol. 2, Advisory Report No. 15, page 177.

creased substantially, and at a more rapid rate than for similar-sized fossil units. This component cost increase apparently has not yet been a deterrent to the competitive position of nuclear plants. For purposes of this report it has been assumed that nuclear plants will continue to be competitive, for units of 800 Mw and up, although for comparable sizes and construction types, nuclear units will cost at least 20 percent more than coal fired units.

The major attraction of nuclear generation particularly in the New England-New York areas is its very low fuel cost, coupled with its practically non-existent fuel transportation cost. The absence that is also particularly significant in the metropolitan areas of Region I of atmospheric pollutants is another advantage. Drawbacks to nuclear generation are:

(1) Some opposition to locating such units close to centers of population—the heavy load centers.
(2) The very large unit sizes necessary to obtain the lowest possible installed capital costs as needed for competitive status.
(3) The need for highly trained, highly paid, and very scarce technical and supervisory personnel.
(4) The necessity for operating at high capacity factors to realize low total costs.
(5) The need for increased volumes of condenser cooling water relative to fossil fuel units.

Current concern about air pollution and the probability of air pollution control regulations in most of the metropolitan areas within the next few years introduces a large element of uncertainty into current fuel-use forecasts. However, it seems safe to predict an even higher percentage of nuclear generation, more interest in "mine mouth" coal-fired plants remote from populated areas, more intensive development of low-sulphur fuel sources and emission control systems, and generally higher energy costs for all electric utilities. These higher costs eventually must be borne by the consuming public.

The choice of fossil fuel to be used in any given generating unit has usually been purely economic—which fuel will result in the lowest cost per Btu produced in the boiler over the life of the unit. The costs to be considered are:

(1) Fuel producer's selling price.
(2) Transportation cost.
(3) User's handling cost.
(4) Conversion efficiency.

To these must now be added a fifth, and at present largely unknown, cost:

(5) Compliance with anti-air pollution ordinances.

In view of the major increase in nuclear generation anticipated for the northeast region, the overall use of fossil fuels is expected to decline during the next two decades. On the basis of an industry survey by the Fuel Resources Committee, the use of natural gas for electric power generation in the northeastern region is the only fossil fuel expected to show an increase, from 100 billion cubic feet in 1966 to 117 billion cubic feet in 1990. The use of coal in this region is expected to decline from 60 million tons in 1966 to 4.0 million tons in 1990. Consequently, the relative position of coal in the total generation of the northeast region may decline from about 67 percent in 1966 to 11 percent in 1990. During the same period of time the absolute use of fuel oil may decrease from 76 million to 37 million barrels.

The Nation's known coal reserves are more than adequate to meet all the needs of the electric utilities, and all other users, through and well beyond 1990. Slightly over one-half of the Nation's total reserves of bituminous coal are within the three eastern regions covered by the Committee survey, and about one-third of this reserve is in the Appalachian area.

Most of the total reserves of low-sulphur bituminous coal are in this same Appalachian region. However, very large investments will be required for any extensive mining of this coal; it is more costly to mine, it is generally at a greater transportation distance from the points of use than is conventional coal, and there is considerable competition for it from other industries. All of these factors indicate considerably higher delivered costs than for conventional bituminous coal.

The long-term mine price of coal has trended downward until recently due to mechanization and improved productivity. For the future, however, the results of this Committee's survey indicate increasing cost of coal at plants for electric generation. This is particularly true for the Northeast, because of the long haul distances from mine to generating plant.

Most electric utility coal moves by rail, and here the development and use of "unit trains" has resulted in important cost savings. Further development of this concept into high speed "shuttle" trains may result in some transportation efficiencies, al-

though rates for coal are increasing at the present time. The practicality of pipeline transportation of coal has been proven by a 108-mile line which operated successfully for several years. Further developments in pipeline transmission may well change the coal transportation picture considerably. Water shipments of coal have increased appreciably in recent years and are expected to continue as an important part of overall coal transportation. In spite of anticipated improvements in transportation, however, coal is not expected to be competitive with nuclear fuel in many areas of the Northeast during the 1970–1990 period.

Improvements in the technology of, and reduction in the costs of Extra High Voltage (EHV) AC and DC transmission are making the transportation of "coal by wire" more attractive. It appears that within the next few years it will be economically practical to transmit blocks of 3,000 to 4,000 Mw from mine mouth plants to load areas 600 to 700 miles away. This technique may become especially attractive because of the probability of less acute air pollution problems in mining areas than in large metropolitan areas. However, dependence of a metropolitan area for its power supply upon long transmission lines introduces reliability problems in the event of major line outages. Solution of these and other problems appears expensive and may well cancel out part of the savings otherwise possible.

The delivered cost of natural gas to electric utilities has remained relatively stable since 1960. The Committee's survey indicates, however, that such cost is likely to increase. Gas is the easiest and least expensive of all fossil fuels to handle at electric generating stations, and the burning of gas minimizes air pollution problems. The role of natural gas in the generating of electricity in the Northeast is contingent on adequate supplies, and other factors, including regulatory policy with respect to optimum use of this depleting natural resource.

Technology is available today for shipping large quantities of gas in a liquefied state. Cost studies indicate, however, that it will be some time before liquefied natural gas (LNG) becomes economically attractive to utilities covered by this report, except for possible emergency use.

Fuel oil (residual) has been of importance in power generation only in the coastal areas of the Northeast. The future use of this fuel is contingent on federal import policies and economic factors. Furthermore, domestic refineries now produce more profitable products from crude oil, resulting in less residual production. For these reasons it is expected that few new oil-burning utility generating units will be built.

Table 10 summarizes the anticipated use of major fuels for electric power generation in the Northeast during the 1970 to 1990 period.

Coal

As a result of increasing efficiencies in the production, distribution, and transportation of coal and in its utilization for power generation, coal accounted for approximately 65 percent of fuel consumed by electric utilities in the United States in 1966, on a total Btu basis.

Each year sees increasing quantities of coal used for the thermal generation of power on a national basis, and it is generally accepted that, quantitatively, the trend will continue upward well beyond the period covered by this report. The question is how it will relate, percentagewise, to other energy sources in response to changes which already are taking place in the energy mix, including the growth of nuclear power generation and growing pressures for the reduction of air pollution. In the Northeast, the combination of air pollution problems of the eastern seaboard megalopolis, and its relative remoteness from coal sources, militate against the use of coal for boiler fuel to the point that total coal consumption for electricity generation is expected to decline about 36 percent between 1970 and 1990.

For the types of coal conventionally used for power generation, recoverable coal reserves are more than adequate to meet all foreseeable requirements far into the future. Reserves of low-sulfur bituminous coals also are substantial. Because of higher mining costs and longer distances for transport, however, the costs of such coals will be higher and their availabilities will differ more or less directly in relation to the levels of sulfur content established in pollution abatement regulations. Furthermore, the characteristics of low sulfur coal are not always suitable for all types of furnaces.

Mounting interest in air pollution abatement has added new dimensions to the appraisal of coal reserves, their quality, and their availability for power generation. Principal among these is increased emphasis on coals of low sulfur levels, for the scope of coal availability narrows progressively as sulfur specifications become more restrictive. A corollary factor of importance is higher delivered prices for some of these coals, as compared to coals

TABLE 10

Coal, Oil and Gas Fuels for Electric Generation, Northeast Region (Based on Survey by Fossil Fuel Resources Committee), Years—1966–1990

	Quantity	Equivalent tons	Quantity	Equivalent tons	Quantity	Equivalent tons
	1966		1970		1975	
Northeast:						
Coal (Millions of tons)	57.9	57.9	63.0	63.0	61.8	61.8
Oil (Millions of Bbls.)	76.5	19.1	69.5	17.4	57.4	14.4
Gas (Millions of cu. ft.)	100.2	4.1	148.5	6.1	162.4	6.7
Total		81.1		86.5		82.9
	1980		1985		1990	
Northeast:						
Coal (Millions of tons)	56.8	56.8	48.8	48.8	40.6	40.6
Oil (Millions of Bbls.)	47.8	12.0	41.3	10.3	37.5	9.4
Gas (Millions of cu. ft.)	146.6	6.0	129.1	5.3	117.5	4.8
Total		74.8		64.4		54.8

Fuel quantities are based on kilowatt-hour generation by fuels and weighted average heat rates, respectively; reported on the F.F.R.C. questionnaire, and were computed using the following conversion factors: 12,500 Btu per pound of coal; 150,000 Btu per gallon and 42 gallons per barrel of oil; 1,030 Btu per cubic foot of gas. The oil and gas equivalents per ton of coal are 4 barrels of oil and 24.3 MCF of gas, respectively.

conventionally used for thermal generation, resulting from both higher mining costs in some production areas and longer transportation distances.

The development of commercial processes for the reduction of sulfur in coal or the removal of sulfur oxides from stack gases will permit the continuing use of medium and higher sulfur coals. Indications are that laws and regulations will either (1) restrict the sulfur content of fuels consumed to levels consistent with whatever considerations are pertinent to the respective areas, or (2) establish limitations on the sulfurous content of stock emissions into the atmosphere following combustion.

Regional Distribution of Coal Reserves

Coal-bearing formations are widely distributed throughout the nation (Figure 9). On the basis of quantity, about 70 percent of the reserves are west of the Mississippi River. These deposits, however, are principally subbituminous coal and lignite, whereas the eastern coals are bituminous and anthracite. On the basis of calorific value, about 55 percent of the total reserve is east of the Mississippi River and about 10 percent is within the northeast region covered by this report. None of the western coal is expected to be used in the Northeast before 1990.

The Appalachian region contains some of the largest reserves of high-quality, high-rank, coals in the United States. The estimated total remaining reserve in the northeast portion of the region is about 50,000 million tons, of which 75 percent is bituminous coal and the remainder Pennsylvania anthracite.

The Appalachian region is the Nation's storehouse of high-grade coking coals. Notwithstanding heavy demands on these coals for the coke ovens of the U.S. steel industry (to which many of them are committed for the future through captive ownership), for export, and for low-sulfur coals to meet air pollution standards, the coking coal reserves of this region are more than adeqaute to meet all foreseeable demands of the metallurgical coke industry. It has been estimated that Appalachia contains approximately 55,000 million tons of "measure" and "indicated" reserves of metallurgical coal of over 28 inches in thickness which contain no more than 8.0 percent ash and 1.25 percent sulfur. This can be considered a minimum reserve using generally accepted standards for coking coal. Generally, these coals also are excellent for electric utility plants where air pollution is a problem, although their costs are appreciably higher than lower-grade coals conventionally used for steam-

COAL FIELDS OF THE UNITED STATES

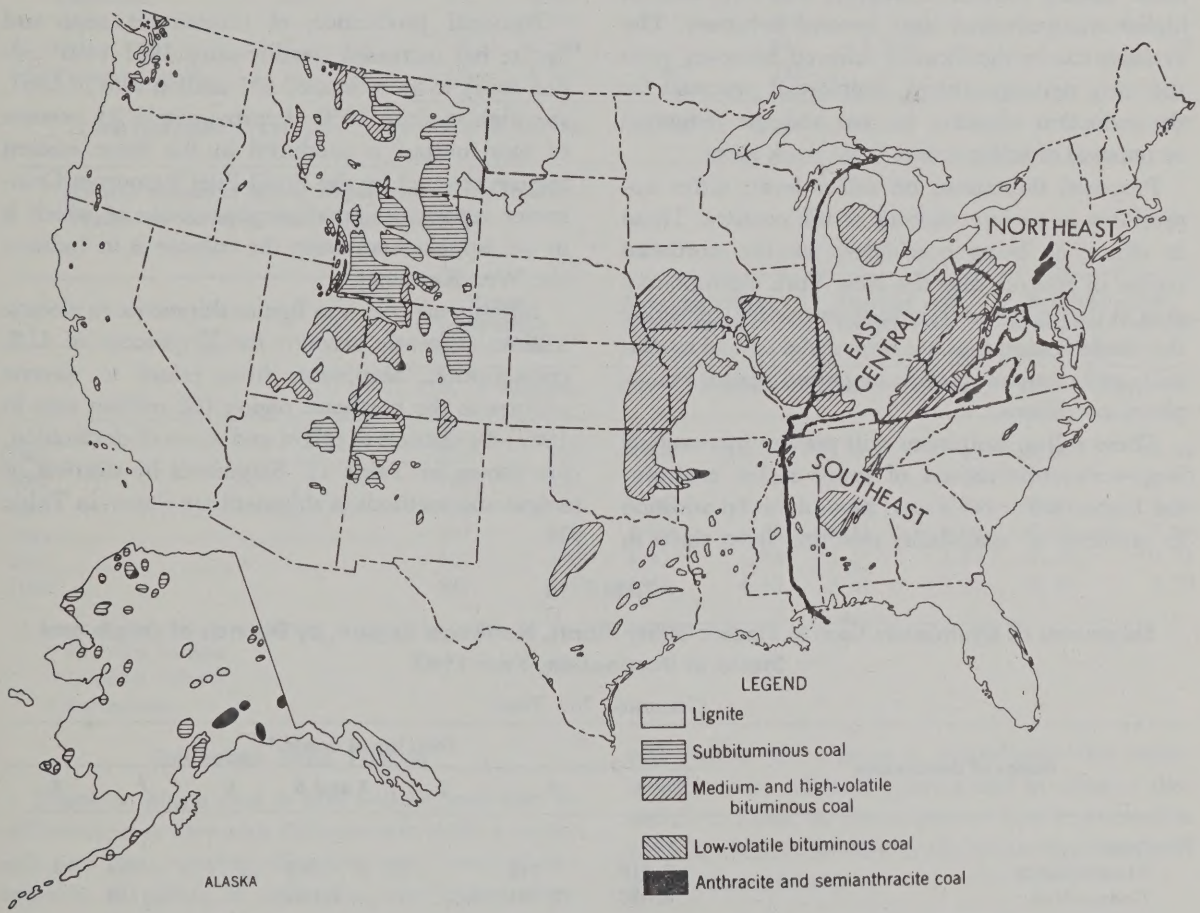


Figure 9

power generation. The measured and indicated reserves of these coals are expected to increase further as exploration transfers additional "inferred" reserves to these categories.

Air pollution has become a matter of major concern in the highly congested areas of the Northeast, so the availability and cost of low-sulfur coals are of prime importance to the coal and electric utility industries of the region and also to the general public. Increased costs inevitably will follow where substitutions of higher-grade fuels, available from more distant sources of supply, and therefore at higher transportation costs, become necessary. The problem can be significantly relieved, however, with the early development of commercial processes for the reduction of sulfur in coal and the reduction or removal of sulfur oxides from stack gases.

Proposed limitations on sulfur levels differ appreciably in various sections of the country. Those in effect, or being considered for the northeast region in general, and the New York metropolitan area in particular are relatively restrictive, reflecting the consideration that has been given to coal availability and economic costs as measured against atmospheric conditions.

These sulfur limitations will require increasingly large-scale substitutions of lower sulfur coals for the higher sulfur coals used heretofore. In addition to problems of availability resulting from shifts in sources of supply and changes in burning facilities, substitutions generally will mean increased costs of coal. Lower sulfur coals are in higher-cost mining areas than the coals conventionally used for power generation. The latter includes large quantities of strip-mined coals. Also, for the most part, lower sulfur coals originate in mining areas at greater distances from points of utilization than previous sources of supply, which correspondinglv increases transportation costs.

Production and Consumption

National production of bituminous coal and lignite has increased steadily since 1961 (403 million tons) to an estimated 551 million tons in 1967, the highest since 1958. Approximately 83 percent of total output is produced in the three eastern regions covered by the Fossil Fuel Resources Committee report, the great preponderance of which is in the Appalachian area; the balance is in Indiana and West Kentucky.

Bituminous coal and lignite shipments to electric utilities currently account for 57 percent of U.S. consumption. Shipments from mines to electric utilities in the northeast region (62 million tons in 1967) by districts of origin and states of destination, are shown in Table 11. Shipments by districts of origin and methods of shipment are shown in Table 12.

TABLE 11

Shipments of Bituminous Coal to Electric Utility Plants, Northeast Region, by Districts of Origin and States of Destination, Year 1967

[Thousand Net Tons]

States of destination	Districts of origin [1]						
	Total	1	2	3 and 6	4	7	8
Northeast:							
Massachusetts	3,418	743	2	961		64	1,648
Connecticut	4,030	2,791		1,091		112	36
Maine, New Hampshire, Vermont, Rhode Island	719			532			187
New York	14,330	4,271	163	7,939	239		1,718
New Jersey	6,402	1,671		4,600			131
Pennsylvania	23,595	11,306	5,882	6,360			47
Delaware and Maryland	8,713	5,273	179	3,217			44
District of Columbia	546	447		4		95	
Total Northeast	61,753	26,502	6,226	24,704	239	271	3,811

[1] 1—Eastern Pennsylvania; 2—Western Pennsylvania; 3 and 6—West Virginia Panhandle; 4—Ohio; 7—West Virginia and Virginia; 8—West Virginia and Virginia.

Source: Bureau of Mines, Department of the Interior (Any differences between "shipments to" and "consumption at" electric utilities represent coal in transit, consumption from stocks, and other balancing factors.)

TABLE 12

Shipments of Bituminous Coal to Electric Utility Plants, Northeast Region, by Districts of Origin and Method of Shipment, Year 1967 [1]

[Thousand Net Tons]

Methods of shipment	Percent	Districts of origin						
		Total	1	2	3 and 6	4	7	8
Northeast:								
All-rail	55	34, 074	15, 700	1, 059	16, 899	239	95	82
Great Lakes		129			129			
Tidewater	23	14, 483	4, 599	21	6, 000		176	3, 687
Truck	12	7, 151	5, 176	1, 975				
River	7	4, 148		2, 430	1, 676			42
Tramway, etc.[2]	3	1, 768	1, 027	741				
Total Northeast	100	61, 753	26, 502	6, 226	24, 704	239	271	3, 811

[1] Source: Bureau of Mines, Department of the Interior.
[2] Tramway, conveyor, and private railroad.

Year	Total production (million tons)		Average value f.o.b. mine		Average rail freight rate		Average mine value plus average rail rate	
	U.S.	Eastern	U.S.	Eastern [1]	U.S.	Eastern [2]	U.S.	Eastern
1961	403	336	$4. 58	$4. 64	$3. 40	$3. 45	$7. 98	$8. 09
1962	422	352	4. 48	4. 56	3. 32	3. 39	7. 80	7. 95
1963	459	383	4. 39	4. 46	3. 21	3. 28	7. 60	7. 74
1964	487	406	4. 45	4. 52	3. 11	3. 16	7. 56	7. 68
1965	512	426	4. 44	4. 54	3. 13	3. 17	7. 57	7. 71
1966	534	442	4. 54	4. 65	3. 01	[3] 3. 05	7. 55	7. 70

[1] Excludes Illinois.
[2] Includes Illinois.
[3] Preliminary.

Delivered Price Factors

Prices at which coal is and will be available in different areas vary with differences in mining methods and costs, quality, distances from point of extraction to points of utilization, and many other factors. Among the principal components of delivered coal prices are (1) the f.o.b. mine prices of coal and (2) transportation costs. The following table indicates the relationship between these two factors and trends for the period 1961–1966 for bituminous coal and lignite for the U.S. as a whole and in the three regions covered by the fuels task force report (referred to below as "Eastern").

As indicated in Table 12 in the northeast region covered by this report all-rail shipments predominate as the method of transportation. Movements via tidewater, river, Great Lakes, truck, and tramway vary in importance in accordance with differences in coal originating areas and in areas of destination. Table 13 shows costs of coal consumed in 1966 at electric utilities in the States that comprise the northeast region.

Mine-Mouth Power Plants

The location of power generating facilities in coal-producing areas, at or near the mines has been practiced for many years on a more or less localized basis. With important technological advancements in EHV transmission which permit the distribution of power over increasingly greater distances, and the further development of intertie, or grid systems, the potentials for increased growth of the mine-mouth concept have been broadened significantly. Table 14 shows new "mine-mouth" plants

with units of 500 megawatts or more that serve or will serve loads in the northeast region.

"Mine-mouth" plants have many advantages to both the coal and electric power industries. Among these are lessening of air pollution problems, particularly in those metropolitan areas in which generating facilities to meet increasing consumer demand would otherwise be located. They reduce the need for and the cost of transporting and handling coal in bulk form, as well as problems of storage and ash disposal in metropolitan areas. They give coal an increased and "captive" market which otherwise might be served by competing energy sources. They also make coal-generated power available for the encouragement of economic enterprises over wider distances, from the local producing areas all along the line to distant consuming markets.

TABLE 13

Coal Consumed by Electric Utilities, Northeast, Year 1966

States	Installed capacity MW	Net generation GWH	Coal consumed (1000 tons)	Average Btu per pound	Cost per ton: F.o.b. plant	Cost per ton: As burned	Cost per million Btu: F.o.b. plant (cents)	Cost per million Btu: As burned (cents)	Percent coal/all fuels (Btu basis)
Northeast:									
Massachusetts	3, 793. 1	19, 717. 3	3, 725	12, 788	$8. 73	$8. 98	34. 3	35. 1	45
Connecticut	2, 235. 5	12, 363. 1	4, 429	12, 857	8. 03	8. 24	31. 2	32. 0	84
Maine	436. 6	2, 400. 8							
New Hampshire	367. 2	1, 726. 3	311	13, 596	9. 40	9. 59	34. 6	35. 3	45
Rhode Island	365. 1	1, 284. 0	375	13, 658	8. 96	9. 87	32. 8	36. 1	62
Vermont	30. 0	57. 8	32	13, 706	N.A.	9. 89	N.A.	36. 1	100
New Jersey	5, 991. 4	28, 749. 8	6, 836	13, 184	7. 78	7. 97	29. 5	30. 2	61
New York State	12, 971. 5	54, 954. 0	13, 079	13, 223	7. 86	7. 97	29. 7	30. 1	58
New York City	8, 909. 3	33, 776. 1	5, 087	13, 459	8. 63	8. 64	32. 1	32. 1	35
New York excluding New York City	4, 062. 2	21, 177. 9	7, 992	13, 073	7. 38	7. 54	28. 2	28. 8	99
Pennsylvania	10, 090. 1	57, 429. 7	24, 124	12, 319	5. 52	5. 74	22. 4	23. 3	93
Philadelphia	3, 205. 2	16, 006. 5	4, 759	13, 516	7. 83	8. 09	29. 0	29. 9	76
Pennsylvania excluding Philadelphia	6, 884. 9	41, 423. 2	19, 365	12, 024	4. 94	5. 16	20. 5	21. 5	100
Delaware	725. 3	3, 382. 6	1, 174	12, 992	7. 33	7. 40	28. 2	28. 5	87
Maryland	3, 484. 0	17, 321. 3	6, 678	13, 081	7. 18	7. 27	27. 4	27. 8	99
District of Columbia	533. 8	916. 5	494	13, 159	8. 35	8. 98	31. 7	34. 1	98
Total Northeast	41, 023. 6	200, 303. 2	61, 257	12, 794	$6. 92	$7. 10	27. 0	27. 8	72

TABLE 14

Mine-Mouth Electric Plants of 500 Megawatts Capacity and Over, Northeast Region [1]—New Plants and Additions Scheduled for 1967 to 1973 Service

Plant	Megawatts	Operational	Operator
Keystone No. 1	900	1967	Keystone group of PJM Pool.
Keystone No. 2	900	1968	Keystone group of PJM Pool.
Conemaugh No. 1	900	1970	Conemaugh group of PJM Pool.
Conemaugh No. 2	900	1971	Conemaugh group of PJM Pool.
Homer City No. 1	640	1969	Pa. Elec. Co. & N.Y.S. Elec. & Gas Co.
Homer City No. 2	640	1970	Pa. Elec. Co. & N.Y.S. Elec. & Gas Co.
Total	4, 880		

[1] There are several additional minemouth plants with units of less than 500 megawatts.

Source: FPC "Steam-Electric Plant Construction Cost and Annual Production Expenses," various annual supplements.

Natural Gas

The continued importance of natural gas to the fuel economy of the electric industry is unquestioned notwithstanding the phenomenal growth of nuclear power projected in the next two decades. The relatively pollution-free quality of natural gas has enhanced its value for producing electric energy, at least for the short term.

Natural gas requirements for all purposes in the United States during the next two decades are expected to increase at an average annual rate of approximately 3 percent, rising from 17.8 trillion cubic feet in 1966 to 36 trillion in 1990.[2] Gas as fuel for electric generation represented 14.6 percent of total U.S. natural gas requirements in 1966. Natural gas consumed in producing electricity in the northeast region covered by this report will increase by about 62 percent over current consumption levels by 1975, and then decline to 17 percent over current levels by 1990. Gas will account for only 1.3 percent of total electric generation in 1990 compared to 4.7 percent today.

Reserves

Proven recoverable reserves of natural gas in the United States, exclusive of Alaska and Hawaii, approximated 286 trillion cubic feet as of December 31, 1966, according to estimates of the Committee on Natural Gas Reserves of the American Gas Association.[3] This is equivalent to about 12,000 million tons of high grade bituminous coal and is sufficient to last about 16 years based on 1966 net production of 17.5 billion cubic feet.

The additional gas that ultimately may be discovered and produced—the potential gas supply—has been estimated as 690 trillion cubic feet as of the end of 1966. This estimate was made by the industry's Potential Gas Committee under the sponsorship of the Mineral Institute of the Colorado School of Mines, and represents gas supply not proved by drilling and therefore classified as "probable," "possible" or "speculative" depending upon geologic conditions and degree of exploration.[4] The Committee's estimate by supply areas and classifications is as follows (Trillion standard cubic feet):

	East	Central	West	Total
Probable	55	220	25	300
Possible		170	40	210
Speculative	60	80	40	180
Total	115	470	105	690

The East supply area in the foregoing tabulation is approximately coterminous with the Northeast, East Central and Southeast Regions of the National Power Survey study.

Coal Gasification

Natural gas as fuel for electric generation in the United States during the five-year period from 1961 to 1966 increased from 1.8 to 2.6 trillion cubic feet,[5] an average annual growth rate of 7.4 percent for the period. The gas used for electric generation represented 14.6 percent of total natural gas requirements of 17.8 trillion cubic feet in 1966.

In the Northeast, it is estimated that gas for electric generation will increase from 100 million cubic feet in 1966 to 162 million in 1975, and then decline to 117 million by 1990.

To the extent that natural gas for electric generation is off-peak or "valley" gas, it tends to promote pipeline economy by permitting a higher load factor operation than otherwise would be possible if pipeline loading were determined solely by gas consumers' daily and seasonal requirements. This results in lower rates for gas service to consumers.

The Federal Power Commission, which has jurisdiction over gas use through its regulation of interstate pipelines, has in special situations authorized some additional gas for use in electric generation. The Commissions policy in this respect is to determine the public interests in each individual case, balancing long-term conservation against short-term benefits of air pollution control and fuel economics.

The price of gas at the wellhead and to the consumer, including electric utilities, has remained relatively stable since 1960, as shown below.[6]

[2] Future Natural Gas Requirements of the United States, Vol. No. 2, June 1967.

[3] Potential Supply of Natural Gas in the United States as of December 31, 1966, Prepared by Potential Gas Committee.

[4] Ibid.

[5] Federal Power Commission: Electric Power Statistics.

[6] American Gas Association, Gas Facts, 1966.

Average Wellhead and Consumer Price of Natural Gas

Year	Average wellhead (cents/ MCF)	Consumer cost by class of service (Cents/MCF)		
		Residential	Commercial	Industrial (Including Electrical Utilities)
1960.....	14.0	97	77	33
1961.....	15.1	100	78	34
1962.....	15.5	100	79	35
1963.....	15.8	100	79	35
1964.....	15.4	100	78	34
1965.....	15.6	100	78	35
1966.....	15.9	100	77	35

Gas-Fired Total Energy Systems

Gas-fired total energy (TE) systems which combine on-site electric generation with waste heat utilization for air conditioning and process heat have been achieving increasing acceptance by the commercial and industrial market since the early 1960's. The number of installations was about 100 in 1964, in excess of 430 in 1967, and is expected to rise to 680 by the end of the 1968.[7]

A recent market study conducted for GATE (Group to Advance Total Energy) by Battelle Memorial Institute predicted a potential TE market of 72,000 new and existing commerical buildings through 1971; approximately one-fourth of these buildings are located in the eastern section of the United States.

Liquefied Natural Gas

The shipping and storing of liquefied natural gas (LNG) has only recently advanced from the theoretical to the commercially feasible stage. The first commercial shipment of LNG, from Algeria to the United Kingdom and France, was delivered in 1964. More recent contracts provide for large deliveries of LNG from Alaska to Tokyo, commencing in 1969.[8]

In the United States, several gas transmission companies are studying the economic feasibility of importing substantial volumes of LNG from Venezuela to provide new sources of gas to supplement their domestic supplies. The objective is to deliver pipeline quality gas in New York at competitive rates.[9]

Coal Gasification

Technology for producing low-Btu synthetic gas from coal has long been available. The major emphasis in the development of coal gasification processes today is on the production of high-Btu gas with a minimum heating value of 950 Btu per cubic foot. A product of this quality could be blended with natural gas without seriously diminishing unit heating value, and could be transported economically through new or existing pipeline systems from points of manufacture to centers of consumption.

For different reasons, government, coal interests, and elements of the natural gas industry have joined to support research and development in coal gasification: government—to broaden the energy resource base; the coal interests—to develop new markets for coal; and the natural gas industry—to insure a long range supply of economical gaseous fuel. There has been a significant increase during the past five years in efforts directed toward coal gasification.

There are several reasons why coal is receiving favorable consideration:

1. Coal is an abundant indigenous resource.
2. Coal prices tend to remain relatively stable.
3. Coal is a relatively inexpensive feedstock for gasification processes. In most areas of the country coal or lignite is available at 10 to 20 cents per million Btu at the mine, whereas the price of the lowest grade petroleum product that might be used as feedstock for gasification is 40 to 50 cents per million Btu.

At present, the cost of manufacturing gas can only be estimated. With coal at 15 to 16 cents per million Btu the cost of producing gas by any one of the proposed gasification processes would be about 50 cents per million Btu. Depending on the size of the plant, the price of coal, credits for byproducts (sulfur), assumed rate of depreciation, and anticipated average return on equity capital, synthetic pipe-line quality gas might be as low as 40 cents per million Btu. At present, the average price of natural gas available for resale near centers of consumption is 35 cents per million Btu.

[7] Electric Light and Power, February 1968.

[8] Business Week, February 19, 1966; Oil & Gas Journal, January 1, 1968.

[9] Oil and Gas Journal, November 20, 1967.

Residual Oil

The outlook for residual oil for electric generation has been somewhat dimmed by two major developments since the National Power Survey was issued in 1964. First, the sudden emergence of environmental quality as a major public concern and the resulting emphasis on low-sulfur fuel. Second, the widespread acceptance of nuclear power with its economic incentive and its appeal as a pollutant-free source of energy, notwithstanding certain urban siting problems still to be resolved. The impacts of these and other developments are reviewed in this study.

Domestic residual fuel oil production dropped 21 percent between 1960 and 1966 despite increased refinery crude runs, as refineries converted their residuum to more economically attractive products. Asphalt production increased almost twice as fast as crude runs, while coke production grew almost three times as fast.

Electric utilities reporting to the Federal Power Commission [10] increased their use of residual oil for electric generation from 86 to 141 million barrels between 1961 and 1966. The annual rate of increase was much greater in the later years but averaged 10 percent for the period.[11] Most residual oil is used in the coastal states where large tanker deliveries from Venezuela and, more recently, from Africa, minimize transportation cost.

Electric utilities in the Northeast included in the recent survey conducted for this report estimate that during the next two decades the amount of residual oil for electric generation will decrease both in absolute value—from 77 million barrels in 1966 to 38 million barrels in 1990—and percentagewise from 22 percent to 3 percent of total generation.

Federal Oil Import Policy

Restrictions on oil imports were imposed by the President under the Trade Agreements Act of 1955 as extended in the Trade Expansion Act, which authorizes him to impose quantitative restraints on imports if they threaten to impair national security. The Oil Import Administration, under the supervision of the Assistant Secretary—Mineral Resources, Department of the Interior, discharges the responsibilities imposed upon the Secretary of the Interior by Presidential Proclamation 3279 of March 10, 1959, as amended, "Adjusting Imports of Petroleum and Petroleum Products Into the United States." This proclamation, made in the interest of national security, imposes restrictions upon the importation of crude oil, unfinished petroleum oils, finished petroleum products, and residual fuel oil to be used as fuel. The Administration allocates imports of these commodities among qualified applicants and issues import licenses on the basis of such allocations.

Interior Secretary Udall announced on March 25, 1966, a program for the year beginning April 1, 1966, which amounted to a substantial relaxation of control of fuel oil imports into District I. However, the Presidential Proclamation still provides for controls, and the control can be reestablished at any time.

In the long run, however, it might be most desirable to pursue policies which would encourage competition among all fuels, including low-sulfur fuel oil. Although nuclear generation is making great strides toward becoming the dominant mode of electric power generation in the Northeast, residual fuel oil will continue to play an important role in satisfying the constantly growing need for fuels for electric power generation.

On July 17, 1967, the Proclamation was amended to encourage imports of low-sulfur residual fuel oil and the manufacture of low-sulfur residual fuel oil, from imported crude oil, to help abate air pollution. This was accomplished by:

(1) Changing the definition of residual oil to include No. 4 oil.

(2) Easing low-sulfur residual import allocations in District V.

As a result of the relaxation of controls, there have been substantial increases since 1966 of imported residual fuel oil available to the electric power industry. At the present time, the Federal Oil Import Policy appears to have improved the competitive position of high-sulfur residual fuel oil for the electric power market in the Northeast, Eastern Seaboard, and Florida areas. Numerous and highly restrictive air pollution control regulations have been enacted in areas of the Northeast, requiring that residual fuel oils, if used, be of low-sulfur content. These regulations introduce new factors in the competitive picture. As a result, consumers of fuel oil are apprehensive about the long-

[10] Oil used in 1966 by electric utilities covered by this report is shown in more detail in Table 12.

[11] Federal Power Commission: Electric Power Statistics.

range effect of the low-sulfur fuel oil requirements and the possibility that artificial controls may be introduced at later dates in an effort to preserve traditional trade relationships.

Oil From Coal and Shale

Potential synthetic crude oils processed from reserves of coal, oil shale and tar sands afford greater national security than the alternative of increasing reliance on oil imports. Industry sources estimate that 2.5 trillion barrels of synthetic oil could be recovered from United States coal reserves, plus 650,000 million barrels from U.S. oil shale and 300,000 million barrels from Canada's tar sand.[12] Synthetic crudes are not expected to be significant fuels for power generation in the Northeast before 1990.

Nuclear Power

Introduction and Summary

Nuclear power technology progressed steadily from the days of the Shippingport, Dresden and Yankee prototype generating stations of the late fifties till about the end of 1965. At this point, a combination of competition in the budding nuclear industry, practicable light water reactor systems, and electrical system demands for large, economical units coincided. The result was an unparalleled surge in the industry to "go nuclear." During 1966, nearly one-half of the new generating capability ordered was nuclear.[13] This phenomenal growth has been characterized by a broad and intensive industrial participation, with an awareness that the associated manufacturing and uranium industries must develop rapidly to meet the demand. Similarly, the need has become evident for fast breeder reactor development to improve nuclear fuel resources utilization and to better utilize the expected plutonium production of the present generation of light water reactors. The relative availability and cost of fossil and nuclear fuels, improved capital investment aspects of larger nuclear systems, and the impact of air pollution on public opinion have been major considerations in fossil versus nuclear decisions. Indications are that nuclear power will assume an ever increasing role in power production, with a gradual transition to the economically advantageous fast breeder systems as that technology develops, predicted for the 1980's.

The great strides made in nuclear technology and the foresight of the Federal Government in encouraging private industry to put the nuclear industry on a free enterprise basis have gone far toward making nuclear power economically competitive. Fast-rising future energy requirements place even greater demands on development of nuclear power, and exploitation of all our fuel resources, and thus charges government and industry with having to meet these needs through the use of advanced concepts such as the fast breeder system, and more economical construction and operating techniques.

Operating Experience

As of January 1, 1968, there were four operable nuclear power stations in the Northeast, providing about a million kilowatts of capacity. The Connecticut Yankee Unit No. 1 at Haddam Neck, Conn. achieved criticality on July 24, 1967 and reached its present capability of 463,000 Kw in January, 1968. In 1967 the Peach Bottom (Phil. Elec. Co.) high temperature gas-cooled reactor went into commercial operation, demonstrating the practicability of this concept. The Yankee Rowe Plant (Yankee Atomic Co.—1962) of 175,000 Kw capability, has shown over a period of years the practicality and dependability of light water reactor systems. Consolidated Edison's 265,000-Kw Indian Point Unit One (1962) is also building an impressive operating record. Operating, maintenance and availability experience of these units, and twelve others scattered throughout the United States, has been such as to convince the electric utility industry that their new generating requirements can be met safely and reliably by nuclear power.

Nuclear Fuels

A milestone with significant beneficial effect on the electric power industry occurred with the passage of the Private Ownership of Special Nuclear Materials Act of 1964. This permits the orderly transfer from Government to private ownership of enriched uranium and plutonium produced by irradiation. The following table shows the timing of the related changes.[14]

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[12] National Coal Association: Coal News, March 1, 1968.

[13] "The State of the Nation's Power"—C. P. Avila, President EEI, speech to N.Y. Society Security Analysts January 17, 1968.

[14] The Nuclear Industry—AEC, 1967.

TIME-TABLE

Private Ownership Permitted_____	August 26, 1964.
Toll Enriching of Privately Owned Uranium Can Begin.	January 1, 1969.
AEC Prohibited from Entering Into New Lease Agreements for Power Reactor Fuel.	January 1, 1971.
AEC Guaranteed Purchase Price For Plutonium Will Terminate.	December 31, 1970.
Private Ownership of Special Nuclear Material Mandatory, all prior lease arrangements must terminate.	July 1, 1973.

This legislation already has generated, and will continue to generate, desirable competition in the nuclear fuel industry. The only component of the fuel cycle still in government hands is the enrichment process, and the Atomic Industrial Forum with the AEC has initiated a study of the feasibility and desirability of transferring to private industry one or more of the government's gaseous diffusion plants for fuel enrichment. The utilities are exhibiting an increased independence from reactor suppliers in making arrangements for reactor fuel loadings beyond those contracted for at the time of placing the nuclear steam supply system orders. The options available to utilities range from that of the reactor manufacturer's full fuel cycle service to that of the utility controlling many of the major steps in the fuel cycle. Recently, many of the companies involved in the nuclear fuel cycle industry announced plans for moves into, or expansions, to handle the new requirements. This, combined with the transition by the uranium supply industry from the guarantees of a government supported to a private market, is expected to have a long range favorable effect on nuclear fuel economics.

Present and Future Status

The Northeast Region leads the country in installed, ordered, and planned nuclear power generation. In this region are located 4 of the 16 operable nuclear power plants, 6 of the 21 plants being constructed, and 10 of the 40 plants planned.[15] Most of these future units are in the 800,000 kilowatt range, the largest being of about 1,100,000 kilowatts capacity. Nuclear fuels for these plants and others will be available from known reserves, new discoveries, or breeder reactors.

Summary

Table 15 summarizes the anticipated energy source for electric power generation in Region I for the 1970 to 1990 period.

[15] AEC Release—January 11, 1968.

TABLE 15

Electric Generation by Type of Fuel and Hydro Power, Northeast Region (Based on Survey by Fossil Fuel Resources Committee), Years—1966–1990

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	%	Billion Kwh	%	Billion Kwh	%	Billion Kwh	%	Billion Kwh	%	Billion Kwh	%
Thermal Generation:												
Coal	130.5	66.6	157.5	60.0	156.1	41.6	141.9	27.5	122.0	17.9	101.5	11.1
Oil	43.4	22.1	43.8	16.7	36.5	9.7	30.1	5.8	26.0	3.8	23.6	2.6
Gas	9.3	4.7	15.3	5.8	16.9	4.5	15.1	2.9	13.3	2.0	12.1	1.3
Nuclear	2.2	1.1	30.7	11.7	148.5	39.6	309.3	59.8	492.7	72.5	747.1	81.7
Int. Comb	.6	.3	1.3	.5	1.4	.4	2.0	.4	2.4	.3	3.1	.3
Total	186.0	94.8	248.6	94.7	359.4	95.9	498.4	96.4	656.4	96.5	887.4	97.0
Hydro Generation:												
Conventional	10.1	5.2	12.0	4.6	12.0	3.2	11.8	2.3	11.4	1.7	11.1	1.2
Pumped Storage			1.8	.7	3.5	.9	6.6	1.3	12.1	1.8	16.2	1.8
Total	10.1	5.2	13.8	5.3	15.5	4.1	18.4	3.6	23.5	3.5	27.3	3.0
Total Generation	196.1	100.0	262.4	100.0	374.9	100.0	516.8	100.0	679.9	100.0	914.7	100.0

CHAPTER III

ELECTRIC GENERATING FACILITY TRENDS IN THE NORTHEAST 1970–1990

Patterns of Generation Development

The generation development plans depicted on the maps in the Summary and the principal facilities map at the end of the report reveal the continued trend of expected power system load densities in Region I and also the fuel and cooling water effects on generating plant location.

The availability of coal in Pennsylvania has been recognized in the pattern of future generation shown in this report, to the extent believed to be feasible in terms of delivered fuel costs and air pollution considerations. A number of relatively large fossil-fueled plants are anticipated in central and western Pennsylvania.

Several large oil-fired plants are expected along the Atlantic Coastal areas. These sites offer economic installations for generating stations fueled with oil which can be delivered by sea-going tankers.

The megalopolis area from Washington, D.C. to Boston is expected to continue as the most concentrated load area of the Region, and for this reason the largest number of generating plants will be found there. The availability of coastal waters as a source of cooling for the large stations anticipated also makes the megalopolis area a naturally desirable area for plant sites of the future.

The rather dramatic trend toward the installation of nuclear units, as urban siting of nuclear generation becomes practical during the 1970 to 1990 period is due both to economics and the solution which these plants offer to the problems of air pollution. This trend will result in a large concentration of nuclear plants in all of the heavy load areas of Region I except in the Pennsylvania coal areas mentioned above.

A large number of desirable pumped storage sites are available in the Region, and the peaking requirements which economically can be met from such sources in an area served by nuclear base load stations, is expected to lead to the development of several large pumped storage facilities in the years ahead. Inventories of pumped storage sites in Region I, both existing and undeveloped, may be found in Appendix A.

Some opportunities exist for expansion of conventional hydroelectric capacity, but the amount involved is relatively small in comparison with total additions. Gas turbine capacity will be added, where appropriate, to carry peak loads, to help maintain system reliability, and to optimize investment costs.

Higher voltage interconnections between companies and systems, together with reduced availability of suitable generating sites, will act to increase plant sizes for all types of generation.

Fossil-Fueled Plants

Fossil-fueled thermal plant sizes may increase to 5000–7000 megawatts by 1990, even though such a large investment at one place may not now seem prudent or justified. Unit sizes may increase to as much as 1500 megawatts by the end of the period; pressures and temperatures have temporarily leveled off at about 3500 psi, and 1000°/1000° F but will probably go higher as technology improves. Reliability is becoming increasingly important, and the previous rapid advances of higher steam conditions are tempered by the need to more thoroughly prove the expected gains. Heat rates may be further improved, but again in much smaller increments, and by improvements in boiler efficiency, better exhaust and condenser design, and possibly by use of combined cycles, to take advantage of the thermal efficiencies inherent in their design.

Automation and precise controls will be necessary to properly and adequately control the tremendously concentrated energies of the super-sized generating units. Operations by computer and automatic control, including the most difficult procedure of starting pulverized coal fired units, will become more commonplace. Controlled heating and expansion of boiler and turbine parts on startup and shut-down will be required to eliminate damage by thermal

stresses and to avoid unnecessary maintenance of the large units, thereby assuring high availability. Response of machines to spinning reserve contingencies will have to improve as sizes increase and fewer total units are on the line at any given time. Boiler response to sudden system changes in generation or load will have to be faster than it is today, particularly in being able to utilize stored energy for rapid load pickup and before the solid fuel combustion process readjusts the rate of heat release.

Fuel supply in storage as protection against production or transportation stoppages or other problems will represent a major inventory investment for large concentrations of generating capacity at a given site. Sixty-day supplies are presently commonplace, and may have to be increased to seventy-five or even ninety, to adequately protect against shortages.

Automated transmission safeguards against generation upsets caused by loss of a large unit, loss of major sectors of load or disturbances of frequency and/or voltage will be more important as systems continue to expand and protection of components from damage becomes more vital to reliability and availability. Reliability of plant auxiliaries has improved to the point where spare equipment is not usually included in new designs; better maintainability and more complete stocks of parts protect against long time outages due to auxiliary failures.

Leveling off of the unprecedented increases in size of boilers and turbines, and increases in steam conditions observed over the last decade, signals the realization that operating experience must catch up to predictions and justification for the advances. Boiler tube metallurgical difficulties have been responsible for reduced availability of many units operating at advanced pressures and temperatures. Under current technology, unit reliability is primarily related to the boiler and its auxiliaries, particularly the boiler tubing, and it is in this area that improvement must be made.

Investment costs per kilowatt are normally expected to decrease with increasing unit size, but, in addition to inflation, the demands of the middle 1960's for cleaner air, reduced thermal discharges to streams and lakes, and aesthetics, are absorbing the dollars saved by building larger facilities. Higher stacks, better precipitators, sulfur dioxide collection processes, cooling towers, and better architecture and landscaping where necessary, all add to the cost of any size unit. However, size helps to hold the line on total cost per kilowatt. As explained in the preceding chapter, fuel costs for coal and oil with reduced sulfur content are increasing now, as are some freight rates along the east coast. Disposal of ashes continues to be a problem as coal quality deteriorates and less desirable reserves are tapped. Efforts are under way by the coal, cement, and utility industries to develop and further the use of flyash in various ways to help with this mounting disposal problem.

Power production costs have historically decreased with time as improvements were made to the thermal efficiencies of plants, and as unit sizes increased; these efficiencies have now reached a point where possible gains are much smaller for conventional units. Also, the prices of labor, maintenance, and fuel continue to rise. All of this will tend to reverse the production cost trend. At best, it now appears that this cost will gradually level off unless a new breakthrough in the basic method of power production occurs.

The demand for turbine generators, boilers and reactors has become so heavy in recent years, that lead time from placing of orders to commercial operation has stretched to seven years in the case of nuclear steam turbines, and to at least five years for conventional turbines and boilers. While this is hopefully a short-ranged problem, it cannot be entirely disregarded for long-range studies and therefore project planning must be advanced to accommodate these conditions. Construction planning methods are becoming more sophisticated to hold this period to minimum time limits, with more precise shipping schedules for materials and components to minimize construction delays.

Nuclear Development

The domestic-nuclear power program continues to be broad in that there still is much required in research and development, design, construction, and operation of many types and sizes of nuclear reactors. Experience must still be obtained from the operation of many types under development to demonstrate their capital and operating costs, dependability, and flexibility. However, operating experience gained from the continued operation of the Dresden, Yankee, and Indian Point No. 1 nuclear units plus that from recent startup and preliminary operation of Connecticut Yankee has confirmed the earlier confidence in the reliability, dependability, and flexibility of the water-moderated

and cooled reactor variety. Thus, while nuclear research and developments may demonstrate the advantages and importance of other types, the projections presented in this report are based primarily on reactors of the PWR and BWR types until the mid 1980's when it has been assumed fast breeder prototypes will have successfully demonstrated the advantages and operating acceptability of such a type.

Operating Experience

Considering the fact that the plants are of the first generation, the power generating records at the Yankee and Indian Point nuclear units have been good. The cumulative gross generation from the first full year of commercial service in megawatt-hours, is 6,750,000 for Yankee and 5,605,000 for Indian Point, for average gross plant factors of 69 and 47 percent over their respective operating periods, based on current capacity ratings. The performance of the two reactors has demonstrated the dependability of this type for a nuclear steam supply source.

Operating experience from Connecticut Yankee and Peach Bottom No. 1, the only units coming into service in Region I since the 1964 report, while satisfactory, is of so short duration that reporting in detail has not been thought desirable.

Size

Capital cost differential against nuclear units as compared to fossil-fuel units has continued. However, this differential has decreased significantly with increase in unit size and should also be further decreased as air pollution abatement receives more attention.

With the concept of field fabrication of reactor vessels an accepted fact, the transport limit on size will have been eliminated. As a result, reactor units of 2500 Mw capability are conceivable by the late 1980's. However, for the purpose of this study, a size limit of 2000 Mw has been assumed as a practical objective and good match for transmission.

It has been assumed that engineered safeguards will be so thoroughly demonstrated by the mid to late 1970's, that urban siting will be quite acceptable However, no assumption has been made that containment or engineered safeguards will be relaxed.

Nuclear Power Economics

The study estimates of the unit capital costs of large single reactor plants, assuming construction is initiated early in 1967 and completed by 1972, are shown on Figure 10. It is to be understood that extrapolation to the larger-sized light-water moderated and all fast-breeder reactors depict greater probable error as these units not only are yet to be designed, but they will have their beginning in the decade 1980–1990.

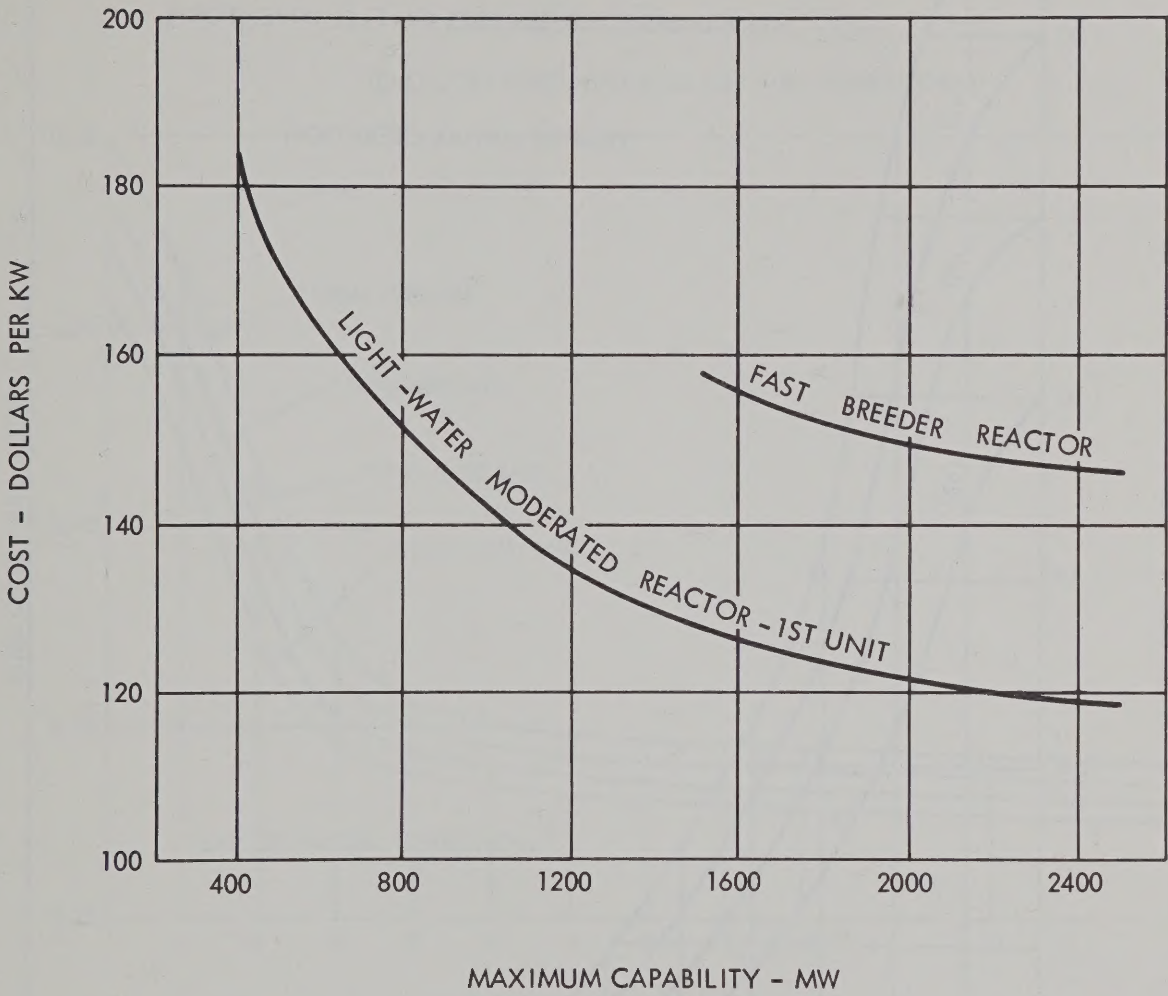
Nuclear fuel costs based in the price level anticipated for 1972 operation are shown on Figure 11 for a light-water moderated reactor, and on Figure 12 for a fast breeder. The costs depicted by these curves excludes fixed charges and fuel inventory.

Growth of Nuclear Power

The presently installed nuclear power capability in Region I is approximately one thousand megawatts or about 2 percent of the total electrical capability. However, there is under construction 3,400 megawatts and on order over 12,500 megawatts with in-service dates through early 1974. Presently, there are four major suppliers of nuclear steam systems competing for the electrical generating business, and these augmented by competent field fabrication of large pressure vessels contribute materially to the nuclear power growth for Region I. This growth rate is such that by the early 1970's nuclear power may be accounting for about seventy percent of the capacity being installed. It is probable fossil capacity additions will be continued, to a limited degree, through 1990 in the coal producing areas and the remainder of the nonnuclear capacity installed will consist of developable hydro, quick start thermal peaking, and large blocks of pumped storage. These plants will complement the nuclear generation by improving capacity factor operation, thus improving overall performance of the nuclear plants. By 1990, the nuclear capability of the Region may be over 100,000 megawatts with 25 percent of this capability in fast-breeder reactors and the remainder in the water-moderated and water-cooled variety.

There is a possibility that other thermal reactors may prove competitive in the period under study. One such is the high temperature gas-cooled reactor under development by General Atomic as incorporated in the 40 Mw Peach Bottom No. 1 unit recently placed in service, and the 330 Mw Fort Saint Vrain (Colorado) plant now in design. Favorable results from this advanced converter concept could stimulate sufficient interest to result in some capacity additions of this type in Region I.

ESTIMATED CAPITAL INVESTMENT FOR NUCLEAR PLANTS



NOTE: COST OF LANDS AND SWITCHYARD EXCLUDED. INTEREST DURING CONSTRUCTION INCLUDED. ESTIMATES BASED ON FIRST QUARTER 1967 STUDIES OF COSTS THEN EXPECTED, FOR PROJECT TO BE COMPLETED IN 1972.

IN THE PERIOD SINCE THE CHART WAS PRODUCED (JANUARY 1, 1968) COSTS HAVE BEEN RISING SHARPLY: CONSIDER THIS FACT WHEN REFERRING TO CHART.

Figure 10

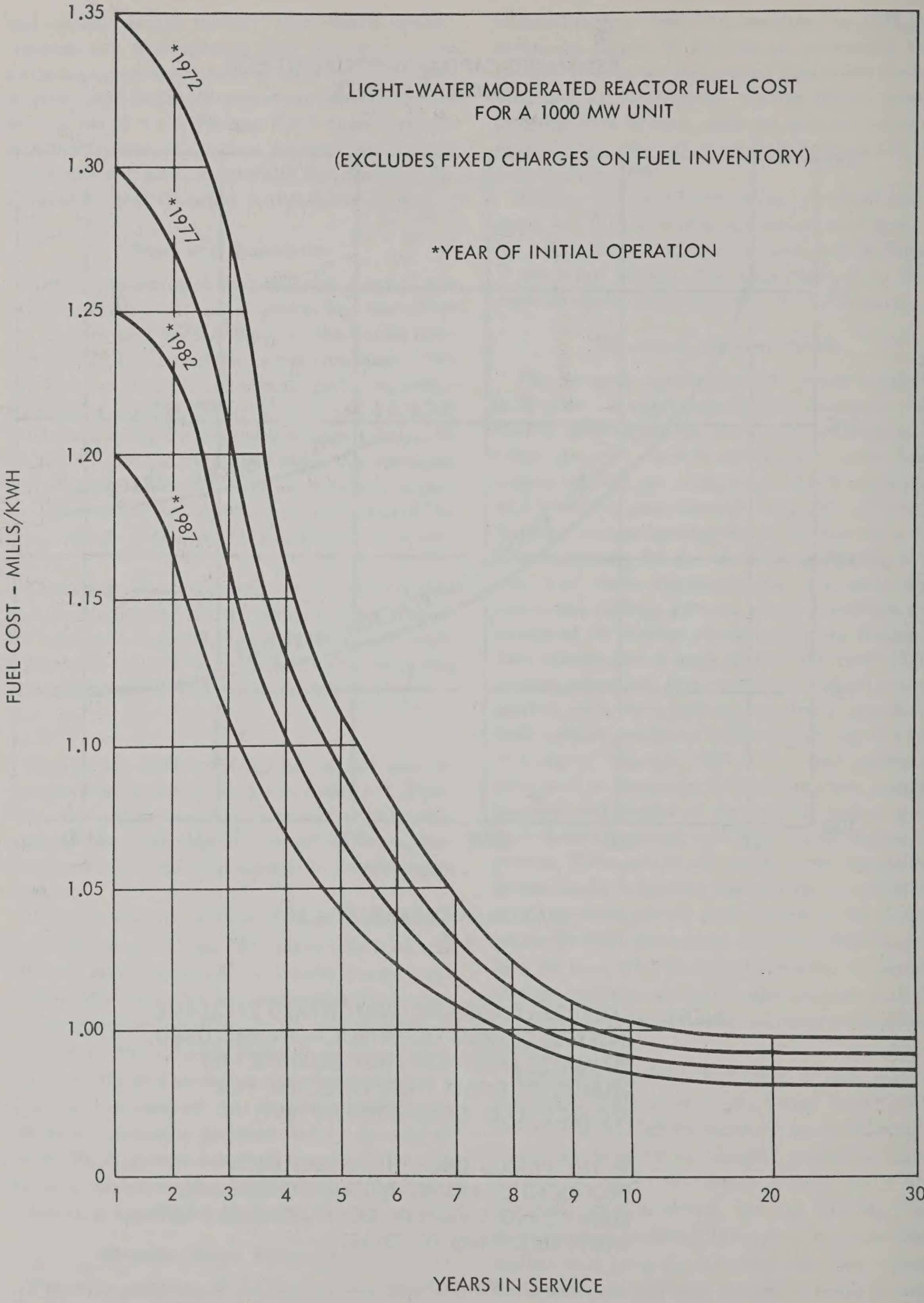

LIGHT-WATER MODERATED REACTOR FUEL COST
FOR A 1000 MW UNIT
(EXCLUDES FIXED CHARGES ON FUEL INVENTORY)
*YEAR OF INITIAL OPERATION
*1972
*1977
*1982
*1987
FUEL COST - MILLS/KWH
1.35
1.30
1.25
1.20
1.15
1.10
1.05
1.00
0
1
2
3
4
5
6
7
8
9
10
20
30
YEARS IN SERVICE

Figure 11

FAST BREEDER REACTOR FUEL COST

(EXCLUDES FIXED CHARGES ON FUEL INVENTORY)

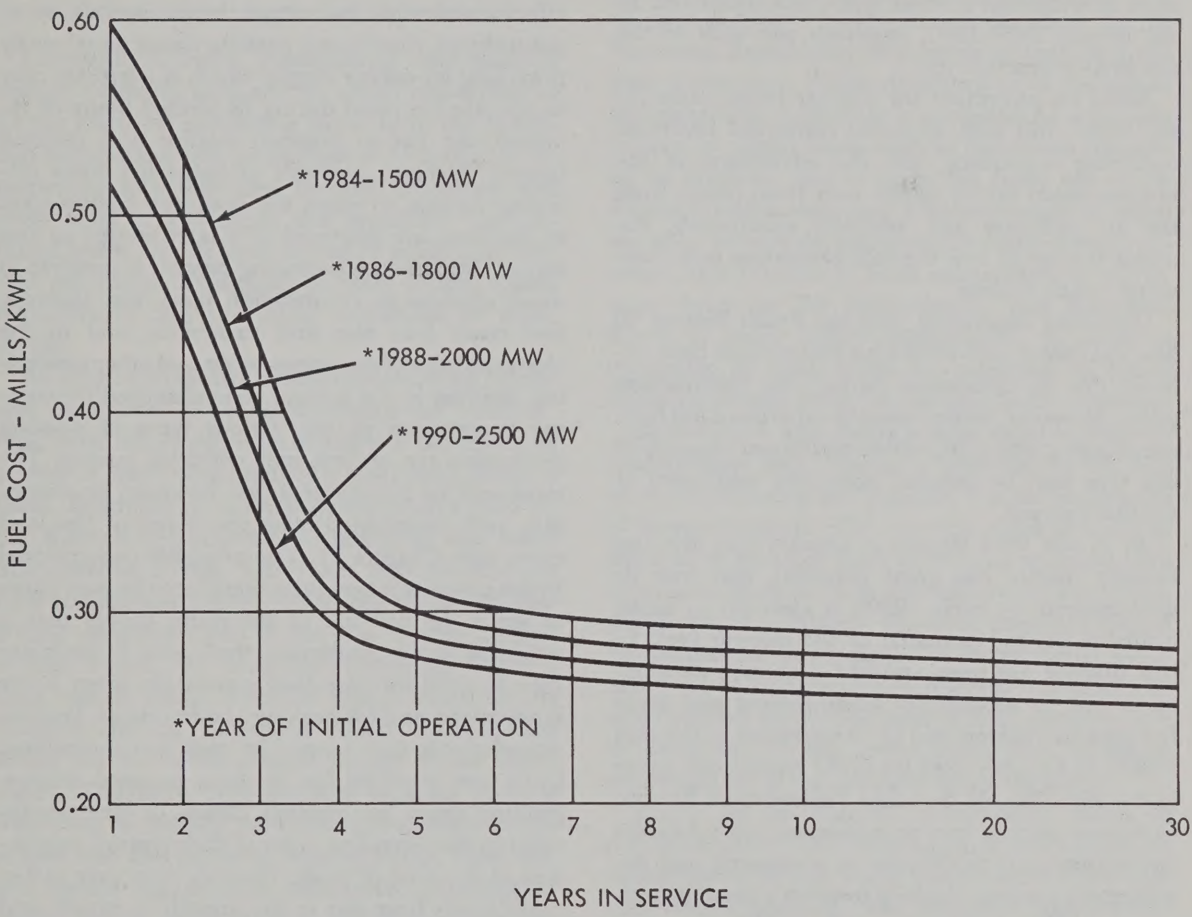


Figure 12

Fusion (Nuclear) or Thermonuclear Power

It has been assumed that useful power from fusion will not be achieved during the period under review.

Conclusions With Respect To Nuclear Power

In this study, the emphasis has remained on the proven water-moderated and water-cooled reactors for additions to system capacity through 1980. However, development of other types have continued. In the decade 1980–1990, emphasis will shift to the fast breeder reactor type.

Based on projection for nuclear power costs for the larger unit sizes, expected continued favorable operating experience, and the advantages of the nuclear steam supply system over fossil plants from the air pollution and aesthetic standpoints, the major portion of new thermal generation to be provided will be nuclear.

Operating experience with the Peach Bottom 40 Mw gas cooled convertor-type reactor had been delayed due to difficulties during the construction phase. However, several months experience has been encouraging and it is possible additional capacity of this type may be planned about the mid point of the study period.

As in the 1964 Report it appears that the fast breeder reactor has great potential, and that its development by early 1980's is essential to make available the full potential of the nuclear fuel. In this study it has been assumed that such development will be successfully accomplished and large fast breeder reactors will be in operation in the mid 1980's. In October 1967 the GPU system took a step in this direction. At that time Pennsylvania Electric Company entered into an agreement with Atomics International to participate in a research and development program looking towards a possible decision by 1970 to install a 350 to 500 megawatt sodium-cooled fast breeder reactor.

Hopefully, proven safety and public acceptance of nuclear plants will permit urban siting by the mid to late 1970's.

Hydroelectric and Peaking Generation

Characteristics of Generation for Peak Loads

Generation for peak loads differs from other generation only in that it is required to operate discontinuously and for relatively short periods. This requirement can be met by most types of generating facilities, with the exception that serious operating difficulties are encountered when the load on high-pressure, high-temperature steam turbines is varied rapidly. Consequently, the choice of facilities to carry the peak of the load is wide, and should be governed by overall system economics rather than by the specific suitability of particular forms of generation.

The need to operate for short periods provides an opportunity for cost savings. These savings may be accomplished by sacrificing fuel economy to effect a reduction in investment (as in the case of gas turbines, diesels, and peaking steam units) or by providing an energy supply which is adequate only to operate the plant during its limited hours of required use (as in pumped storage and peaking hydro). General methods of balancing these offsetting factors, to select the optimum combination of facilities, are discussed in a later section of this report. Because the balancing process is sensitive to small changes in construction costs, site features, fuel costs, load size and variability, and to the characteristics of the transmission and other generating facilities in the system, generalizations concerning proportions of the various types of peaking generation are, at best, only educated guesses. The total peaking requirement can, however, be reasonably well determined from the shape of the load curve (see Chapter I). The available conventional hydro capacity is generally fitted into the load curve to make the best use of the water supply that is available at any particular time, so a hydro plant may be used for base load generation when water is abundant, and for peaking at other times. Peaking requirements that cannot be met by conventional hydro are provided for by using pumped storage, peaking steam, gas turbines, diesels, or other equipment in the ascending order of their costs of production at the time of peak. The mix may vary rather significantly from day to day, month to month, and year to year.

The rate at which the various types of peaking capacity will be added to systems in the Northeast defies precise advance determination. It can be presumed, however, that where physical sites for economical pumped storage are available, and so long as relatively low-cost energy for pumping can be provided by essentially base-load equipment, pumped-storage will constitute a major portion of the peaking equipment addition. It can also be presumed that some additional diesel and gas-turbine units will be acquired because of their advantages for peaking and for providing at-site run-down and start-up power for the large base-load

plants of the future. The use of cycling steam units may be less widespread, but some utilities will find peaking steam units to be advantageous. Speaking very broadly, peaking equipment will probably provide 15 to 20 percent of the total generation capacity between 1970 and 1990, with hydro providing about half of the peaking capacity and fueled units providing the other half.

Conventional Hydroelectric Power

Conventional hydro, distinguished from pumped storage currently accounts for about one-eighth of all the electrical generating capacity in the Northeast Region and this proportion is declining as the remaining available sites become developed and other types of generation are expanded. Conventional hydro may be used for either peaking or base load generation, depending on plant design, system requirements and prevailing conditions of water supply.

Existing hydroelectric developments in the Northeast are of three general types. One is the "cascade" type, in which a long reach of a river is developed by a series of dams with essentially level pools between them. Examples of cascade developments exist on the Kennebec, Racquette, Connecticut and lower Susquehanna Rivers. The rivers may or may not have controllable storage to regulate the stream flow during the greater part of the year. During periods of high runoff, the available storage may have a flood control effect. A second type is found on the Niagara and St. Lawrence Rivers where plants utilize the enormous natural storage of the Great Lakes. The third type includes separate projects with integral storage that generally operate partly as base load and partly as peaking plants. They can, and usually do, produce substantial quantities of energy beyond those required to support their firm capacities during some seasons of the year.

The advantages of hydroelectric power are well known and include: high availability; quick starting and flexible operation; absence of pollution; and predictable and relatively low maintenance and operating expenses, due, in large part, to the absence of any cost for fuel. The disadvantages usually include: high capital costs; remote locations, often far from centers of demand, with consequent expenses for long distance transmission lines; dependence on variable stream flows and other natural factors beyond the control of man; and operating restrictions imposed by competitive water uses which may override power generation.

The capital cost to develop hydroelectric power in a conventional plant with gated intakes, massive river control works, and other expensive features varies widely, but generally is the highest of any form of power generation. These costs depend, among other things, on the nature of the site, the type of structure contemplated, and the extent of relocations necessitated by the project. Since most of the good sites have already been occupied, the cost of new conventional hydro development in the Northeast Region may be in excess of that for available alternatives. Public development of the best of the remaining potentials is proposed by some advocates to permit lower costs to the power consumers in the area, and to make the fuller use of the Region's hydro resources. Redevelopment of existing sites, to provide additional or more efficient capacity, is a possibility. Such redevelopment at certain plants on the Susquehanna and Kennebec Rivers is under active consideration, as noted in Appendix A. Such plans are intended to obtain optimum service from the nation's hydro resources.

Appendix A also shows a substantial number of undeveloped sites, having a potential of 50 Mw or more. Inclusion in Appendix A is no implication of economic merit. The reservoir areas of some of the sites so included have become so occupied with other developments that construction of the hydroelectric plant is unlikely. However, there are limited possibilities for development of conventional hydro as a part of comprehensive reservoir projects, and as an adjunct to pumped storage. Such potential will be developed to the extent practicable to obtain maximum use of the available water resources.

There are no Federal hydroelectric plants in the Northeast but the Congress has authorized power developments at the Tocks Island and Dickey-Lincoln School projects. The proposed conventional power installation at the Tocks Island reservoir project on the Delaware River would have a capacity of about 70 Mw. However, a non-Federal pumped storage development has been proposed which would pump water from Tocks Island reservoir to a reservoir on Kittatinny Mountain and discharge either above or below Tocks Island dam. If this scheme of development is adopted the plan for a conventional power installation may be abandoned.

The Dickey-Lincoln School project would be on the Saint John River in Maine. The Corps of Engineers, in Fiscal years 1966 and 1967, spent nearly $2 million on plans for this project but the Congress did

not appropriate additional planning funds for use in either fiscal year 1968 or 1969. This development would have an installed capacity of 830 megawatts, capable of producing an average of 1,154 million kilowatt-hours annually.

Appendix A contains an inventory of existing conventional hydro plants in the Northeast Region.[1] That appendix shows that, of the 5,890 Mw of conventional hydroelectric capacity in 281 plants in the region, 33 percent is located on the Niagara River, 15.5 percent on the St. Lawrence, 14.8 percent on the Susquehanna, and 8 percent on the Connecticut. The distribution by states is New York—63 percent, Maryland—9 percent, Pennsylvania and New Hampshire—7 percent each, Maine—6 percent, Vermont and Massachusetts—3 percent each, and Connecticut—2 percent.

Pumped Storage

Pumped storage capacity is becoming an important source of peaking capacity in the Northeast Region. In 1963, only two pumped storage plants, Rocky River (31 Mw)[2] and Lewiston (240 Mw) were in operation. Since that date, Yards Creek (338 Mw) and Muddy Run (800 Mw) have been placed in operation. The latter is the largest pumped storage plant in the United States. Two projects, Seneca (330 Mw) and Northfield Mountain (1,000 Mw), are under construction. Capacity operating and under construction totals 2,715 megawatts. Four license applications, Cornwall (2,000 Mw), Longwood Valley (135 Mw), Bear Swamp (600 Mw), and Blenheim-Gilboa (1,000 Mw), are pending before the Federal Power Commission. One application, Kittatinny Mountain (1,300 Mw) is pending before the Delaware River Basin Commission. The five projects for which applications are pending would add 5,035 megawatts of new capacity. The Northeast Region is fortunate in having a large number of sites suitable for pumped storage plants. Many additional sites have been identified and some are being studied for possible development.

Existing pumped storage capacity in this region is largely concentrated in New Jersey and eastern Pennsylvania, where there also is a heavy commitment to construction of nuclear plants. Nuclear and pumped storage combinations are currently being studied for development on a large scale throughout the Region.

Pumped storage plants have been compared with storage batteries and other kinds of energy accumulators. The comparison stems from the way the plants operate, as indicated by the following description of typical pumped storage operating routine: The pumped storage plant uses energy generated in steam electric plants during night time hours, or other low demands periods, to pump water into a high reservoir, where it is retained temporarily. At some later time, during periods of high demand, the stored water is released to produce hydroelectric power as it falls back to its original elevation. Due to unavoidable losses in the cycle, pumped storage plants actually consume about three kilowatt hours of thermal energy to lift the quantity of water which eventually will generate about two kilowatt hours of hydroelectric energy. The disadvantage with respect to energy is more than offset by low investment cost and other desirable characteristics which have made pumped storage attractive to utilities in the Northeast Region.

A pumped storage plant, even with a very high head, generally has the same favorable operating characteristics as a conventional hydroelectric plant—rapid start-up and loading, long life, low operating and maintenance costs, and low outage rates. By pumping in the offpeak hours, the plant factor of the thermal units is improved, thus reducing severe cycling of these units and improving their efficiency and durability. No additional capital investment is required to produce the pumping energy, so, in effect, the only significant cost of such energy is for the fuel consumed. Elements of the public have objected, with considerable effect, to the siting of certain pumped storage works and, particularly, to the appearance of associated transmission lines. Similar objections will undoubtedly be voiced for other pumped storage developments.

Meeting aesthetics requirements will increase the cost of pumped storage, although it is unlikely that these considerations will control the economic feasibility of well-conceived projects. Aesthetic considerations are major factors that must today be taken into consideration in planning any type of generation or transmission.

Since 1963, an analysis of recreational potentials, and the inclusion of a plan for recreational develop-

[1] See also Federal Power Commission publication "Hydroelectric Power Resources of the United States—Developed and Undeveloped".

[2] Plant includes a 24-megawatt conventional unit and two 3.5-megawatt reversible units. About half of the water supply for all generation is pumped, on a seasonal basis.

ment where opportunities exist, have been mandatory for all hydroelectric projects to be licensed by the FPC. In addition, there are many cases where water power developments, including pumped storage, have been studied as part of regional recreational and water resources development plans. Pumped storage project reservoirs are not generally well adapted to recreation development because of the rapid fill and drawdown cycles that make them both unattractive and in some cases dangerous. This is particularly true of the upper reservoirs that usually have relatively small capacities, and fluctuate from near-empty to full. Even so, the pumped storage projects can provide a focal point for recreational development with park areas, trails, overlooks and other facilities provided as integral parts of the project. The Northfield Mountain project now under construction in Massachusetts is a good example. At the Muddy Run project in Pennsylvania the upper reservoir has a controlled section where a near-constant water level will be maintained for fishing and other recreational use.

Several pumped storage projects planned for the Northeast include functions other than power and recreation. Both the Northfield Mountain project and the Yards Creek project in New Jersey will pump water across river basin divides, for delivery to municipal water supply storage systems. The Longwood Valley project in New Jersey will also provide joint storage for municipal water supply and power.

Water power projects contribute substantially to recreation and conservation, but the limitation of power in respect to the other features of a project must be recognized. Water power generation causes water level fluctuations, even in large reservoirs, and unduly restrictive limitations on plant operation may jeopardize the feasibility of a power project. Users of the many-purpose developments must tolerate a certain amount of aesthetic discord between the natural landscape and power generating and transmission works. If the power plant and the transmission lines must be buried underground, then the capital cost of the works must be increased, and the power from the plant becomes less competitive with other sources of generation. Indeed, under present technology and costs the general feasibility of any project could be jeopardized by insistence that the project area be entirely free of visible transmission lines. The addition of recreational or other non-power features also increases project costs, without providing any additional revenues.

Appendix A includes an inventory of undeveloped pumped storage sites. It includes projects under construction and those projects for which license applications have been filed. As in the case of the unconstructed conventional hydro plants, inclusion in this appendix does not necessarily indicate the potential project is economical.

Because of the lack of engineering details and other factors, it is not possible to evaluate the feasibility of, nor provide accurate estimates of cost for developing the potential sites. As an example, in built-up, developed areas, the question of acquiring rights to fluctuate the levels of any existing body of water required as a lower reservoir is so complicated as to require detailed studies, having in mind that excessive costs would eliminate many excellent sites from further consideration. The listed potentials have been selected from a much larger group, and show what are the more desirable sites which might fall into a favorable cost range.

The 69 undeveloped sites listed in Appendix A could provide an aggregate capacity of about 54,000 megawatts. The sites are reasonably well distributed throughout the Region. The 25 sites listed in New England states could provide 22,000 megawatts of capacity; the 20 sites in New York could develop about 15,000 megawatts; and Pennsylvania, New Jersey and Maryland could provide about 17,000 megawatts at the 22 sites listed in that area.

The existing pumped storage plants in the Region are also tabulated in Appendix A.

Gas Turbines

The gas turbine-generator unit has demonstrated its suitability as a source of economical peaking and emergency power. It is low in first cost, quick starting, offers wide choice of site locations, and is readily automated.

Plants with single prime movers of the simple open-cycle type are available in ratings up to about 50 megawatts. These plants are pre-engineered and pre-packaged to minimize field labor. Units of about 10 Mw capacity are shipped assembled, but larger ones are erected in the field on concrete slab foundations. Typically, plants are furnished with a self-contained cooling system, and weatherproofed housings, and include provision for self-contained starting and remotely controlled unattended operation.

Gas turbine units with mulitple prime movers driving single generators are now being offered by manufacturers. One design employs several jet engines equally divided on either end of the centrally located generator. More than ten of this type unit, some rated up to 160 Mw, have been ordered by several utilities. One such unit, rated at 140 Mw, has been operating since 1965. Other designs using different arrangements of multiple prime movers driving single generators are also available and in service.

Gas turbine installations are relatively low in capital costs, ranging generally from $80 to $125 per kilowatt installed, depending upon type and size. The low cost results from the compact, pre-engineered factory packaged design, with a minimum number of station auxiliaries, little or no water requirements and low foundation, building and installation costs.

Units can be remotely started, synchronized, and fully loaded in 2 to 20 minutes, depending on size and type. This feature provides significant start-up, stand-by and manpower savings that must be considered when these units are compared to alternative forms of peaking capacity.

Gas turbines, because of low investment cost and flexibility in location, are adaptable to a variety of peaking uses. These include stand-by reserve capacity, peaking capacity and capacity supply in extended areas of a system when also needed for protection and to assure satisfactory voltage at times of maximum peak demand. An additional application has arisen following the 1965 Northeast blackout, namely the installation of gas turbine-generator units as cranking units for black start-up of steam power plants. The smaller size, 20 Mw or less, gas turbines provide system flexibility because they may be moved from one part of a system to another part, at relatively low cost.

Today's gas turbines have low thermal efficiencies, requiring 13,000 to 15,000 Btu per kilowatt-hour of generation. They are limited to burning high-grade liquid fuels or gas, which are costly in many areas. As a result, energy costs are high. In most cases, the use of gas turbines is limited to annual plant factors not exceeding 5 to 10 percent. Part load heat rates are poor, half load being in the order of 18,000 to 20,000 Btu/kwhr.

Prospects are good, however, for advances that will make gas turbines more useful in the future. Work is being done with a view to developing a coal-burning turbine. The problems of fly-ash erosion of turbine blades is still unsolved but effort continues to be devoted to this difficulty. Gas turbines are under development having improved aerodynamic design and employing higher gas temperatures (made possible in part, by internal cooling of turbine blades) which would result in heat rates of 10,000 Btu to 12,000 Btu/kwhr, and there are advanced cycle concepts which promise 9,000 to 10,000 Btu/kwh. The capability of a gas turbine decreases with decreasing density of its free air supply, so that its rating is influenced by the site altitude and ambient air temperature. The reduction in capacity with higher air temperatures may be a disadvantage for systems having summer peaks. Conversely, the increased capacity at low temperature may benefit winter peaking operations.

Noise is a consideration which may preclude gas turbine plants at certain locations, however, with appropriate attention given to proper sound treatment equipment, gas turbines can be located in residential areas.

Diesels For Peaking

Diesel engines have been used for peaking on power systems for many years. The renewed interest in this type of peaking capacity has resulted primarily from the recent development of low cost, packaged, automatically operated, unattended diesel units. Diesel units, while available in capacities up to 6 Mw, are usually manufactured in ratings of about 2 Mw and are frequently combined in multiples to provide plants of up to approximately 10 Mw capacity. Straight diesel, supercharged diesel, or dual-fuel engines are available. A single engine and generator are usually mounted on a structural steel base and enclosed in a sound suppressing and weatherproof housing, together with lubricating and cooling equipment, and other accessories. Automatic control equipment can be included in this enclosure, or in a separate control cubicle. Plants with multiple units often have all controls mounted in a single cubicle. These package units can be shipped on freight cars or trucks to the site and installed outdoors, requiring very little foundation work.

Many of the operating and economic features of the diesel peaking unit are similar to those characteristic of the gas turbine, but there are significant differences. The capital cost of larger diesel installation is about $100 per kilowatt and the heat rate is about 10,000 to 12,000 Btu per kilowatt-hour. Diesel units have the ability to accept full

load from cold start-up within 60 to 90 seconds. They are well suited to part-load operation and can furnish spinning reserve service. They also can be used for cranking and restarting steam power plants. In the colder climates, energy from an outside source is required to keep the unit warm for quick starting. This is particularly necessary for units at remote locations.

On major power systems diesels are not widely used for peaking capacity, since available sizes are too small. They are sometimes installed for the primary purpose of deferring investment in transmission facilities, or to provide load protection and to assure satisfactory voltage at times of maximum peak demand.

Since these units can be readily and cheaply moved, they could serve this purpose in many different locations on a system over a period of years. Such applications would ordinarily be expected in areas of relatively low load density and growth rate.

Appendix C provides data on existing and committed gas turbine and internal combustion peaking units in the region.

Steam-Electric Peaking

There are two basic approaches to providing steam peaking capabilities, namely:

1. Steam peaking capacity incorporated as an integral part of base units.

2. Steam units designed specifically for peaking service.

Steam Peaking Capacity Integral With Base Load Units

Past experience in carrying higher loads on older units has resulted in some systems incorporating many peaking features in the design and operation of new units. Such incorporation requires detailed design care at critical points, and the installation of instrumentation, measuring points, and other observations by which the overload effects can be evaluated. Generally, efficiency and capacity tests are made at the time of initial installation to be used as a base for evaluating subsequent operating practices. Peaking features typically permit carrying short time peak loads 10 to 20 percent above continuous unit rating with a resultant loss of efficiency. This additional capacity can be achieved for approximately $35 to $55 per kilowatt, with an increase of heat rate of about 20 percent.

Typical devices, designs, or arrangements for obtaining low cost peaking capacity in new steam units are as follows:

1. By-passing high pressure feedwater heaters.

   The high pressure heater, or heaters, can be cut out of service, or by-passed, at peak load times, with a resultant lower extraction of steam and lower efficiency, but higher flow of steam to the condenser. This procedure requires special boiler design to give wider range steam temperature control.

2. Feedwater heating.

   In those cases where the furnace is not capable of more fuel burn to make up for cooler boiler feedwater, the feedwater heating may be obtained from an outside source.

3. Lower steam temperature.

   A temporary reduction in steam temperature will permit the same piping and turbine parts to carry higher steam pressures. These two changes permit an increase in the steam flow and hence greater capacity. This procedure also requires special boiler design to obtain wider steam temperature control range.

4. Spray into reheater.

   Adding excess spray attemperating water into the reheater steam flow, combined with combustion controls for increasing the reheat temperature results in an increase in reheat steam flow and the flow through lower pressure stages of the turbine. This procedure necessitates added boiler-furnace capacity and possibly a larger condenser.

5. Overpressure.

   Since this procedure does not result in efficiency loss, it is frequently adopted for regular continuous use and is mentioned here for information only. It is based on design of most boilers and turbines, for operation at 5 percent above rated steam pressure with proportionate increase in capacity.

Steam Units Designed Specifically for Peaking Service

With a great percentage of all steam-turbine generator equipment on order in the size range of 500–1000 Mw and substantial amounts of limited energy peaking installation, the stage is set for consideration of larger size low capital cost capacity suitable for peaking or long-hour emergency service. At the

present stage of technology steam turbine units are definite contenders to satisfy this requirement.

Basically, steam peaking units are stripped down versions of relatively standard design units. Capital costs of these units range from approximately \$70/Kw to \$120/Kw with heat rates of approximately 10,000 to 11,000 Btu/Kwh. Some of the areas in which capital-cost savings might be achieved are as follows:

1. Reduction of steam temperature to the 950° (or lower) level.
2. The use of oil-firing instead of pulverized coal.
3. Elimination of regenerative feedwater heating, except possibly for the deaerator.
4. Omission of conventional gas-to-air preheaters with associated duct work.
5. Reduction in the duplication of station auxiliaries.
6. Minimizing of automated controls.
7. Installation of an outdoor unit, or one with minimum cost weatherproof enclosure.

Steam peaking should not necessarily be thought of as a substitute for quick-start units but as a complement. For example, steam peaking cannot be started as rapidly as hydro or gas turbines, and it is almost certain that a steam unit having been put on the line to handle an anticipated peak load will not be shut down as soon as a gas turbine. In fact, it frequently would be kept on hot bank, remaining at pressure until the peak of the next day. Thus steam peaking units will most likely be economically justified as "semi-peaking" units designed to operate 500 to 2000 hours per year, and without the capability of rapid starting.

Appendix A lists the existing steam-electric base load units which, by modified operation, can provide a peaking increment, and also describes the three steam-electric units intended specifically for peaking use.

Evaluation of Peaking Capacity

When the growth of system load or the retirement of obsolete capacity makes it necessary to obtain new sources of generation, a selection must be made from among the various available alternatives. Such alternatives, in a general study, include plants of various types and sizes, so selected that the study will yield an optimum combination of base-load, peaking, and semi-peaking units. In a more specific study, the alternatives may be particular generating additions. Regardless of the type of alternatives, the procedure for their evaluation (that is, for a selection from among them) is fundamentally identical.

The choice of different alternatives results in differences in investment costs and in production costs. In general, facilities involving high investment costs per kw result in low production costs per kwh, and vice versa. The general procedure therefore consists in balancing the investment cost against the production cost, taking into account other benefits and costs, the anticipated operation of the proposed facilities, and the effect thereof on the entire system.

The procedure involves comparisons, in four steps, of the annual costs for a number of future years, of owning and operating several entire systems, each of which would serve the same, growing load and none of which would permit its varying factor of safety in meeting its load to fall below a certain minimum. Each such system would include the existing facilities less retirements, one of the alternatives to be evaluated, and a series of subsequent generating additions to meet subsequent load growth which would be sufficiently identical so that differences in the various systems could be ascribed to the alternatives being evaluated and not to the subsequent additions. The four steps (which are facilitated by digital computer programs) are:

1. A statistical examination of system loads, in which the characteristics which will affect the choice of alternatives are determined. The resulting load shapes must be considered both seasonally and over a period of one or more consecutive days.
2. The determination of reserve requirements, in which the data obtained from the first step are combined with growth forecasts, forced and scheduled outages, energy limitations both of the proposed generating additions and of existing facilities, and other factors. This determination yields the size of each type or combination of types of generating additions needed to meet some agreed-upon criterion for reliability in meeting system loads. This procedure is accomplished by simulating or otherwise modelling operation during critical capacity situations.
3. The computation of the annual cost of operating each of the complete systems determined by the second step. This computation consists of a simulation of economic dispatch during normal operating conditions. The

dispatch procedure must recognize incremental cost curves, boiler banking and startup costs, hydro and pumped storage generation limiting factors, transmission penalty factors, varying fuel costs, variable operation and maintenance costs, area protection requirements and spinning reserve requirements.

4. The determination of the cost of owning the capital additions determined by the second step. This includes fixed operation and maintenance costs as well as return, taxes, depreciation, etc.

In addition to the generating facilities, the alternative programs of installation should include transmission facilities sufficient to connect all generation to the load in such a way that the risk of instability or of other transmission failure would be equal for all alternatives.

Year-by-year cost comparisons can then be made of the total of the operating costs (step 3) and the owning costs (step 4), and their present worth determined, or levelized annual costs or their equivalent can be obtained and compared. A detailed discussion of the items to be considered in the economic analysis is included in Chapter VI. The levelized cost has many advantages, but care must be taken that its generalized treatment of the time schedule does not obscure an alternative expansion program in which the recommended facilities are temporarily deferred.

The foregoing method requires the consideration of system loads and of other system facilities. Whether the system to be considered is that of a single company or agency, a pool, or some other entity, depends on other factors, but certain essentials must be recognized. First, all existing facilities plus facilities under construction or committed, must be taken into account, and appropriate derating must be charged against proposed facilities which by reason of limited energy supplies, must be operated in the load in conflict with existing limited-energy generation. Second, when systems are combined to gain the advantages of a larger load in which to operate peaking facilities with limited energy, the fact must be recognized that certain sites which eventually would be useful to one of the separate systems may be displaced by the facility to be proposed for operation on the combined system. Third, account must be taken of the offsetting increase in energy requirements of peaking plants serving combined rather than separate systems, due to the diversity between systems.

Opinions differ as to whether all of the alternatives must be considered to be financed under identical conditions, but there can be no dispute over the statement that, when financing differs, the economic evaluation becomes, to the extent of the difference, an evaluation of the method of financing and not of the alternative types of facilities. The claim has also been made that evaluations should be made on true economic costs rather than on financial costs and that true discount rates for economic costs are related to the risks associated with the proposed development and are therefore independent of the agency or financing device involved.

The procedure described in preceding paragraphs is equally applicable to base-load, semipeaking and peaking capacity. If one alternative to peaking capacity is a high-efficiency base-load addition to the system (and any evaluation of peaking capacity which ignores that alternative, except for one situation to be discussed subsequently, is incomplete), the procedure will take into account the penalty applicable to peaking capacity due to the foregone opportunity to install a base-load plant and thus to reduce system fuel costs. Offsetting advantages, such as reduction in the need for boiler banking, increased efficiency of older units due to more uniform operation, etc., will likewise be considered, if the determination of the owning and operating costs for the various systems is done thoroughly.

The single circumstance under which the inclusion of the high-efficiency alternative is inappropriate is that of the system the existing facilities of which cannot readily and rapidly be varied in output. In such a system, the high-efficiency base-load unit could not be considered, and suitable alternatives would include peaking facilities plus a unit capable of base-load operation but in which efficiency would be sacrificed for cycling ability.

Capacity Retirement Policy

Most thermal plants are depreciated, for accounting purposes, over a 35 to 45 year life, hydro plants over a 50 to 70 year life. As a practical matter, the end of economic life is reached when the out-of-pocket cost of obtaining the desired service from the old plant exceeds the system cost of providing the service from new facilities. The end of economic usefulness is usually reached when maintenance, operating, labor, and fuel costs (for fossil-fired

plants), and any taxes that could be avoided by dismantling the plant, become excessive. Noneconomic factors, such as effects on local public opinion, are also given consideration. The net result is that few utilities have an arbitrary policy for facility retirement. Each case is examined individually and a decision to retire a facility is based on a composite evaluation of economic and other factors.

In the analysis for this report, it has been presumed that a major portion of the fossil plants will be retired when they reach the 35 to 45 year age bracket. All of these retirements are expected to occur in the 1–400 megawatt size range. There will undoubtedly be some retirement of small hydro plants before 1990, but it has been assumed that these losses will be offset by increased installations at other existing hydro developments.

The amount of the anticipated retirements, under these assumptions, are shown on Table 18, in Chapter IX.

Hydro Imports From Canada

The portion of Canada that borders the Northeast Region is served by three electrical systems operated, in east-to-west order by the New Brunswick Electric Power Commission, the Quebec Hydro-Electric Commission and the Hydro-Electric Power Commission of Ontario. The three systems can be loosely interconnected, but ties are normally open and the systems do not operate in parallel with each other.

The New Brunswick and Ontario systems are interconnected with utilities in the United States, and the Ontario system normally operates in parallel with the U.S. systems.

The export of Canadian power to the United States requires an export license. In recent years such licenses have not been granted for long terms, as was commonly done in the past. It is the general policy of the Canadian government that no licenses for the export of power be granted if a need for the power exists in Canada. The growth in power use in Canada during the last decade has exceeded that in the United States and this trend is expected to continue. These and other circumstances have led to seemingly insurmountable difficulties in recent attempts to arrange for importation of large blocks of Canadian power into the United States. Nevertheless, negotiations and cooperative studies are continuing as summarized in the following sections.

New Brunswick Electric Power Commission

Various studies are being conducted regarding the engineering and economic feasibility of a 345 Kv interconnection between New Brunswick and Maine which would link together the power pools of the Maritime provinces and New England. In addition to the normal interconnection benefits, there is surplus power available in substantial quantites from the Maritime pool prior to 1972 (primarily from the new Mactaquac hydro station of the New Brunswick Electric Power Commission on the St. John River). After 1972 this might be augmented by a strong tie between the systems of New Brunswick and Quebec Hydro in which Churchill Falls power could be a factor.

Quebec Hydro-Electric Commission

Hydro-Quebec founded in 1944, serves the entire Province of Quebec. It is one of the few electric utilities in the world to depend almost exclusively on hydroelectric generation. In addition, all but about 32 percent of its capability is located in remote areas. The Manicouagan and Outardes hydroelectric developments, which are currently being constructed, require three 735 Kv transmission lines, each of which will be more than 370 miles long to reach the load in the Montreal area. Churchill Falls, scheduled to be in service by 1972, is approximately 800 miles from Montreal. Since the largest unit on the system is 150 Mw and the generation is predominantly hydro, which has great reliability, Hydro-Quebec maintains a relatively small reserve of about five percent. Because of basic design differences between the Canadian and American systems, the small reserve maintained by Hydro-Quebec and the remote location of their generation, it is improbable that an AC interconnection between Hydro-Quebec and utilities in FPC Region 1 would be stable and reliable.

While no common resource projects similar to Niagara and St. Lawrence in the East or the Columbia River in the West are available between Quebec and the United States, a study was made in 1967 of the feasibility of establishing an interconnection between New England and Hydro-Quebec for the purpose of transporting a portion of the output of Churchill Falls. This study concluded that two asynchronous DC ties would be required to provide the necessary reliability and stability for this proposed sale. Negotiations were terminated

when Hydro-Quebec announced that they would require the entire output of Churchill Falls by 1975 and it became obvious that a short-term sale to the U.S. would not economically justify the large cost of the interconnection.

The Province of Quebec has large undeveloped hydroelectric resources along the great rivers flowing into James Bay, Ungava Bay, and the North Shore of the St. Lawrence east of Baie-Comeau. Studies are presently under way to determine the economic feasibility of these developments. Hydro-Quebec, however, states that the demand for energy is such that the entire known hydroelectric potential of Quebec will not be sufficient to meet 1985 loads. This statement implies that purchases by the United States from these undeveloped sites would also have little chance of being long-term.

While developments such as Manicouagan and Churchill Falls are spectacular, the high cost of transmission from such remote places has the effect of increasing the price of power, and the great length of the circuits tends to reduce dependability. For these reasons, and also because they stimulate the mining industry, thermal stations near the load centers of Quebec are becoming increasingly attractive. Modern nuclear stations have become highly competitive and seem destined to provide most new base-load generation in Eastern Canada as hydraulic power becomes more scarce and expensive. Recent data have indicated that large nuclear stations are in fact second only to hydroelectric plants in economic efficiency. It would appear, therefore, that the development of remote hydro sites would not be as rapid in the future and that the present reserve on the Hydro-Quebec system will move to higher values as large nuclear units are built closer to the load. It may well be that by 1990, a large enough percentage of Hydro-Quebec's generation will be located close to the load so that AC ties with the United States will become practical.

There are two major advantages, however, in using DC to interconnect two large dissimilar power systems. The first is the precise controllability of the power flow between the two systems. It can be scheduled in either direction and at any amount within the capability of the equipment. The other advantage is that unstable conditions in either of the power systems will not be reflected through the DC line into the other. At the present time, the cost of the conversion equipment at the terminal makes the use of DC uneconomic except for extremely long lines, even though the cost of the lines themselves are less expensive than AC. The use of static components and possibly breakthroughs in new equipment may make DC more economically acceptable for use in interconnections in the future.

While the United States would have no real incentive to participate in Canadian nuclear units due to their distance from our load, and no long-term contracts for large blocks of hydroelectric power seem to be available, short-term sales, mutual backup and increased reliability, economic generation dispatch and the lowering of the cost of conversion equipment might make a DC interconnection between Hydro-Quebec and FPC Region 1 attractive at some point before 1990.

Hydro-Electric Power Commission of Ontario

Because of the nature of the Ontario, upstate New York, and Michigan systems, with large sources of generation interconnected by strong transmission links, and because of the extensive collaboration between Ontario Hydro and the Power Authority of the State of New York in the planning, construction, operation and maintenance of works of common interest, there exists a very important requirement for full coordination of planning, reliability concepts, application of protection and communication systems and operating and maintenance procedures amongst those utilities which can have an impact on the reliability and economy of each other's systems. Recognizing this, Ontario Hydro participates fully in liaison and coordinating activities with interconnected utilities in the United States in matters of system design, load and capacity forecasts, capital construction programs and operations. Ontario Hydro joined the Northeast Power Coordinating Council at the time of its formation in 1966.

The Ontario Hydro interconnection agreements with utilities in the States of Michigan and New York at present are exclusively of the voluntary mutual assistance type, providing for all uses of the facilities other than firm power interchange. Thus, emergency peak and energy requirements are provided in both directions as available, transfers of surplus and economy energy are made regularly, some of the facilities are used for important voltage control functions and others for maximizing efficiency in the use of flows available for hydroelectric production. Throughout the period of use of the interconnection, substantial net exports of energy to the U.S. systems have been made, although exports and imports are approaching a balance in

recent years as surplus hydroelectric energy is being absorbed more and more in the Ontario system for displacement of thermal plant energy with its much greater incremental cost.

Although the value of the interconnection has been somewhat restricted by certain operating constraints imposed to maintain reliability standards, nevertheless, the interconnections have provided great value to the adjoining systems. That value is expected to increase as the constraints can be safely removed and additional power interchanges become practicable.

CHAPTER IV

CHANGING TECHNICAL, ECONOMIC AND ENVIRONMENTAL FACTORS

Size of Units

The period between now and 1990 will see an unprecedented expansion in electric capacity in the Northeast Region.

Accomplishing this expansion will pose many new engineering problems for power plant designers. The rapidity of the anticipated growth and the inherent economic and other considerations require that the additions be made with large units. Siting problems and high load densities, brought about by larger population concentrations in the Northeast Region, may justify the selection of larger unit sizes. Thus, by 1990, units of up to 2000 Mw and plants of 5000 Mw will be common. With plants of this size, more interties between pools will be necessary to minimize the effects of forced and planned outages of such large units. These plants will be too large for smaller utilities; multiple ownership of large complexes will be required. The transmission costs will be minimized by the use of high-voltage transmission systems and generation locations near load centers. Coordinated planning by the Northeast Region will be an accomplished fact; far greater interdependence of utilities will be evident.

Siting for Thermal Generating Plants

Land Availability

The size of units that will be common in 1990 complicates the problem of site selection. Transmission, cooling, transportation and other requirements limit the number of suitable locations. The increasing concern over aesthetics also precludes certain areas. These requirements, along with an increasing population and expanding economy, are sure to decrease the number of suitable sites. The decreased number of sites, the probability of inflation, and the increased competition for land are sure to greatly increase land costs. Thus, each site in the future must be selected for the largest generating plant economically justified. Some of the considerations which will limit the size of these plants are discussed in the following paragraphs.

Transmission

The selection of a suitable generating plant site is greatly influenced by the economies of transmission. The usual aim is to locate as close as possible to a load center. However, this choice can be influenced by other factors. For example, mine-mouth location may offset transmission costs with decreased generation costs. Location near an existing transmission network might allow for economical location at some distance from the load center. In general, a balance must be achieved between the transmission and generation costs, a balance that minimizes the cost of electric power. Clean air and cooling water considerations may be so overriding that transmission economics will not be controlling in site selection. When economies and system stability are taken into consideration, transmission considerations may be the deciding factor.

Transmission technology is advancing concurrently with plant size technology. Currently, 765 Kv transmission facilities are being designed and built. Such lines will be capable of transmitting as much as 4000 megawatts of power in a single overhead circuit. Thus, in view of the size of the plants expected in 1990, the addition of such circuits to existing transmission networks is probable. Public sentiment in general is against new right-of-way additions. Therefore, this new technology will mostly be applied to maximize the capabilities of existing networks. This will further stimulate the need for site locations near existing rights-of-way or load centers.

COOLING WATER

General

A limiting factor in the size or location of a thermal generating plant can be the availability of adequate condenser cooling water. Most of the generating capacity increase in the Northeast Re-

gion to 1990 will be with nuclear generating plants. In general, for each megawatt generated as power, nearly two megawatts of heat must be rejected to the environment. Technology will improve this 2 : 1 ratio of heat rejection to power generated, but not sufficiently to materially alleviate the cooling problem.

Cooling Water Requirements

The generating capacity in the Northeast Region by 1990 will be approximately 200,000 megawatts. Of this total, approximately 175,000 megawatts may be fossil and nuclear steam generating plants. Assuming an average efficiency of about 35 percent, the heat rejection to the environment averages approximately 597 billion Btu/hr. at a load factor of 0.5. Assuming an average water mixing-volume temperature rise of approximately 10° F., the required cooling water usage in the Northeast would thus be 450,000 cfs. This figure is equal to approximately one quarter the annual runoff of all the rivers and streams in the United States. Obviously, therefore, sufficient cooling water is not available in streams in the Northeast for once-through cooling of all condensers. Even with use of coastal areas, to the extent practical, supplemental cooling appears to be a necessity by 1990 for much of the Northeast Region.

Site selection will be greatly influenced by the availability of large quantities of cooling water. The water must be as low in temperature as possible and non-corrosive to the materials used in condenser construction. Such considerations as quantity and quality immediately limit future site selection in the Northeast to a few large lowland streams, the Great Lakes, the Finger Lakes and the Atlantic Coast.

Supplemental Cooling Techniques

Many methods are presently used to optimize the use of available cooling water. In general, where sufficient water is available, various schemes can be devised to maximize mixing, and thus minimize the temperature effects on the environment. However, where sufficient water is not available, supplemental cooling is necessary.

On-site supplemental cooling of condenser discharges will be necessary at many sites by 1990. The two general types of supplemental cooling most commonly used in the United States today are cooling ponds and mechanical or natural draft cooling towers.

In the case of ponds, a rule of thumb dictates about one acre of pond surface for every megawatt of plant capacity. As a total cooling mechanism, this method becomes impractical in most areas of the Northeast where both land and dam construction costs are high. Some use such as recreation may be devised for such ponds to help borderline situations, but in general, cooling towers seem to hold greater promise.

Cooling towers can assume either a total or supplemental cooling role. The evaporative consumption of such towers is approximately 0.015 cubic feet per second per megawatt. For a 5000 Mw plant, the consumption would be approximately 75 cfs when the plant is operating at full capacity.

Depending upon climatic conditions, the above amount of water could leave the towers as a vapor cloud. In winter, such a cloud can touch ground and cause local icing or other anomalies of climatology. To avoid the icing, natural draft towers are constructed up to 400 feet in height so that the vapor has a chance to dissipate before reaching the ground. However, from an aesthetic point of view, the size of the towers is objectionable at some locations. Mechanical towers are more suitable for aesthetics, but have the greatest problem with icing. Thus, each situation will have to be judged individually to achieve the best possible cooling method or combination of methods which suits the particular site under consideration.

Other possible methods of cooling are the recirculation of ground water, and dry cooling towers. Neither of these methods will achieve wide use in the Northeast by 1990 because of very high costs. Many sites will use wet towers of various types in conjunction with some straight-through cooling. The variance from location to location will determine the combination that is most suitable. Costs of the supplemental cooling will be between $4 and $10 per Kw.

Limnological Considerations

The Northeast Region has many types of aquatic environments from trout streams to lakes and oceans. Each of these has its own peculiarities and tolerances in terms of cooling water discharges. For example, some tidal estuaries can have organisms which are most sensitive to thermal discharges, while some rivers have temperature tolerant species or organisms which are little affected by typical cooling water discharges. The species and local

conditions vary so much that each stream, reach of stream, lake, estuary, etc., must be examined individually.

In general, different species of aquatic life have an increase in their physiological or metabolic rates as a result of increased temperatures. Heat death of a fish is a complex phenomenon which can involve oxygen starvation, coagulation of body protein or denaturation of enzymes. High temperatures may also stimulate the production of toxic organisms. However, the upper temperature tolerance levels on the whole are poorly known. The inadequacy of the data complicates the problem of determining permissible temperatures at a specific site. Each location has a particular ecological cycle which must be defined. Even when the ecology is defined, statistical data are so scarce that engineering decisions are still difficult.

Since the protection of aquatic life is a growing public concern and will continue to be so through 1990, considerable research will be done on the effects of thermal discharges on aquatic life. Some beneficial effects on the aquatic environment are possible. For example, heated discharges have been used on Long Island Sound in an oyster-culture experiment. Initial results are favorable, and some leading marine scientists have expressed the belief that marine aquiculture could, in the future, include an appreciable degree of cooperation with the power industry.

In view of such facts, it seems probable that some effort will be directed toward more productive use of thermal discharges. For the most part, however, economical power plant operation will require constant conditions which do not allow much variation of thermal discharges for different uses. Thus, only beneficial uses which are consistent with sound operational procedures will be practical.

The facts about the effects of thermal rises in aquatic environments should be determined. Only when such information is available can decisions be made to optimize the environment for aquatic life in the area of thermal discharges. By 1990, the situation should be clearer than at present and efforts will be made to optimize water usage for cooling and other purposes. This may result in using some bodies of water primarily for cooling.

Regulatory Considerations

The regulation of thermal discharges by standards, both State and Federal, probably will be common long before 1990; in fact some states already have thermal standards in effect. In some areas of the Northeast, these standards limit maximum temperatures in warm waters to 85° F. to 93° F., depending on local situations. A temperature rise of 5° F. to 15° F. in warm waters outside of an administratively established mixing zone has also been specified. The particulars of location will determine more specific limits. For more sensitive areas such as trout streams and certain tidal estuaries, more stringent criteria may be applied. These thermal criteria will definitely limit the amount of heat which can be rejected to water bodies. The aim of such regulation will be primarily the protection of aquatic life and the prevention of excessive algal growth. In the establishment of the standards, other considerations such as recreation and other water use may be considered, but these factors may have less significance than the support of aquatic life. Warm water is generally less satisfactory for drinking, household uses, swimming and other recreational activities but in general, the criteria for these functions are adequately covered by requirements for aquatic life. The challenge of such criteria will be to strike the balance which realistically meets health and conservation needs and at the same time permits the required economic development of power throughout the Region.

Transportation Facilities

The availability of easy transportation for fuel and equipment is another consideration in site selection. Construction of the large power plants contemplated for the future can be affected by highways, railroad facilities, water transport facilities, and air service. The more complete and adequate these facilities are, the less costly the construction. Moreover, the construction of nuclear plants can create a particularly severe need for good transportation at a site. Reactor vessels weigh over 600 tons. Such equipment is at present usually brought in by barge, necessitating a site on a navigable waterway. By 1990, such equipment will be field erected, and the water transportation requirement will be alleviated. However, the size of much of the other equipment still makes the availability of water transportation desirable at a site.

Transportation, in general, is good throughout the Northeast Region, and should improve in the future. Therefore, transportation availability at sites in this region should not pose any great difficulties.

FUEL SOURCE AND WASTE DISPOSAL

Fossil Plants

The least costly location of coal-burning plants is generally at mine-mouth. When the plants are located some distance from the mines, coal is usually brought in by train lots, which reduces the transportation cost. Future developments may lead to more transportation of coal in pipelines as a slurry; some such lines may be in use in the northeast by 1990. However, such a method will probably not assume much overall significance in the Northeast because of the increasing reliance on nuclear plants.

Ash disposal from coal-fired plants will continue to be a problem, especially in metropolitan areas. Transportation needs for ash disposal will rise and affect site economics to some degree. In thinly populated areas, the ash may be used as fill. Still some cost will be involved.

Some use for fly ash as lightweight aggregate for concrete may alleviate the economic burden. However, such use will account for only a small portion of the total produced. Other uses will be discovered, but will probably add little toward the solution of the problem.

Nuclear Plants

Nearness to fuel supply is not a significant problem with nuclear plants. Typical fuel elements are easily shipped by a variety of means. Further, the availability of the fuel should rise from increased exploration, the development of the breeder reactor, and improved technology of refining and reprocessing. Thus, fuel supply will not be a significant economic consideration of site selection for nuclear plants through 1990.

The same considerations apply to disposal of radioactive materials as it relates to site selection. When facilities are adequate, site selection will be little influenced by waste disposal. The only possible exception would be for the metropolitan sites which will probably be in use before 1990. Here, because of dense population, costs may increase because of stringent safety requirements. However, in view of the present economics of metropolitan siting, reasonable additional costs should not significantly affect the economics of such a location.

Earth Sciences

A site for a power plant is studied to determine many aspects of its physical characteristics. Such things as underground hydrology must be examined to assess the possibility of contamination of water supplies and for possible supplies of makeup and drinking water for the plant. The ground formation must be capable of providing a sound foundation. Further, the site may be near a seismic fault. The closeness to this fault and the earthquake history of the region are used to set structural specifications. Other physical features, such as topography, also can affect site suitability.

All the above factors are considered in site selection. Physical requirements at sites will continue to be stringent in the future because of the importance of large plants to system stability and reliability. The investment in electric power plants is too great to allow much compromise in the physical requirements of a site.

Meteorological Considerations

The growing public concern about air pollution makes meteorological characteristics of a site assume considerable importance. Although meteorological factors seldom affect the initial choice of the site, the dispersion capability of the local region, in conjunction with other factors such as population density and degree of pollutant control, may limit the size of the plant. Therefore, optimization of plant design based on detailed surveys becomes very important at power plant sites.

Meteorology in an area is greatly affected by terrain features. For example, valleys and ridges tend to channel gaseous effluents in a particular direction. Concentrations at various points in the direction of the release are affected by temperature variations with height, wind speed and gustiness. All these factors must be examined to predict the dispersion of the effluent.

The data are usually obtained by preoperational surveys of the micrometerology of the site for up to two or three years. If possible, these data are then compared with long-term weather bureau data for the region. In this manner, long-term pictures of dispersion are constructed, and accurate predictions become possible. Such items as stack design and height and location of building components are set to optimize dispersion of effluents.

Future sites will be studied in far more detail than those of the past. Additions to sites will be easier from a meteorological point of view since accurate patterns of dispersion will have been established and substantiated. Thus, design of plants will

minimize the air pollution problems. Limits based on tolerable concentrations of pollutants can set maximum plant size.

Other Considerations

In addition to the above, many other considerations are becoming important in site selection. Among these are land use, public acceptance, aesthetics and nearness of state or public parks or historic lands. Public concern about maintaining the beauty of our parks and countryside make large installations undesirable if they are at all objectionable in appearance. Sites are usually chosen to minimize this difficulty; the architecture of plants is designed to blend harmoniously with surroundings.

Population density and franchise area are also factors in site selection. Present Atomic Energy Commission guidelines discourage nuclear plants in densely populated areas. Utilities are reluctant to locate outside their own load area.

Both these factors will be less significant in the selection of future sites. As experience is gained with operating nuclear plants, the degree of their safety and reliability will be more firmly established. This experience, in addition to economic considerations, will permit metropolitan siting. Further, the size of plants, multiple ownership and shortage of sites will probably necessitate locations outside a particular load area.

CHAPTER V

GENERATION RESERVE REQUIREMENTS

Requirements for Reserve Capacity

The electric power systems in the United States plan for the installation of generating capacity in excess of their respective anticipated annual peak loads. This excess capacity provides a margin of reserve to insure against the probability of load exceeding available generating capacity. This safety margin is necessary to provide for the day-to-day variations in the operating condition of the installed generation, and the fact that loads will deviate from estimates.

Generation may become unavailable due to either being forced out, or scheduled out for maintenance. Unit failure, or forced outage, is usually the dominant factor in establishing the required reserve margin. Scheduled maintenance will ordinarily be performed in the low load seasons of the year. However, forced outages are just as likely to occur on the peak load day of the year as on any other day. Thus, if large seasonal load variations exist in a system, the effect of scheduled generation maintenance on required reserve will be small. The converse would be true for a system with relatively small seasonal load variations.

System peak loads are affected by two basic variations: (a) the overall level of the local economy; and (b) the weather. Since the lead time required for the installation of new generation is in the order of five to seven years, the desired generation reserve must therefore be determined five to seven years in advance of need. Thus, system peak load estimates must be based on relatively long range assumptions of business activity, and on some standard weather condition. There are potentials for inherent errors involved in both sets of assumptions. A component of reserve generation is therefore required to allow for the fact that actual system peak loads will deviate somewhat from forecasts.

Since reserve generation can rarely be justified by the economic benefits of its energy production, it represents a major cost increment in utility system operation which there is great economic incentive to minimize. As a measure of this cost, the difference between an installed reserve of 15 percent and one of 10 percent in a 1000 Mw capacity system would represent a capital expenditure in the order of $5,000,000.

Methods of Determination of Reserve Requirement

Electric utilities use three different basic methods in determining the size of their generation reserve:

1. Standard percent reserve.
2. Loss of largest generator.
3. Probability.

All utilities at one time used the first two methods. These have the inherent disadvantage of having no measure of the resultant system reliability. These two methods, however, may be the only practical methods of smaller utilities. The last method, probability, provides an associated measure of reliability, but requires an enormous amount of laborious calculations. With the advent of the computer and the development of appropriate programs, the probability method has become practical.

Standard Percent Reserve

In this method some fixed percent of the forecasted system peak load is used as the required reserve. This fixed percent is usually determined from the past history of a company's own reliability record. Simplicity is the greatest attribute of this method. The changes in load patterns, number and size of generators and generator outage records are usually ignored or handled by gross assumptions. A constant percent reserve will not provide the same reliability for future system conditions as for those of the past. This method, therefore, incurs either excess generation capital costs due to superfluous reserve, or inadejuate reliability due to insufficient reserves.

Loss of Largest Generator

In this method, the reserve will be equal to the size of the largest generator plus, usually, some percent of the estimated peak to allow for load error. This method has an advantage over Method 1, in that the reserve is automatically increased as larger units, with their greater risk, are added to the system. Still the system is again being designed to an unknown variable reliability.

PROBABILITY

Currently popular methods of determining generation reserve requirements make use of probability mathematics. Such methods, permit a desired probability level of generator availability to be designed into the system. With reliability fixed, the installed generation reserve becomes variable, changing with load characteristics and the size and availability of units. Two of the more frequently used basic methods of probability calculations are: (*a*) the loss of load method; and (*b*) the loss of energy method. The former measures required reserve as a function of the probability of loss of capacity required to meet load, usually expressed in units of years/day or its reciprocal days/year. The latter measures required reserve as a function of the percent of total energy expected to be lost or percent of the total energy expected to be served.

The terms "loss of load" and "loss of energy" used to describe these two methods are unfortunate choices of terminology, since they suggest planned dropping of load. Actually, they are intended to express a measure of relative system reliability (e.g., "loss of load one day in ten years" is a higher degree of reliability than "loss of load one day in five years"). Usually, calculations are made with conservative assumptions so that reliability is actually higher than calculated. Also various emergency operating procedures, such as system voltage reduction, may avoid the need to interrupt service to customers due to lack of installed reserve. Even if some customers were dropped in order to balance load and generation, they would usually represent only a small portion of the total load. The average customer's supply reliability as influenced by adequacy of installed generation capacity is many times higher than the designed reliability for the system as a whole. There is always some risk present, and the probability method attempts to define it.

Method of Probability Calculations

The "Loss of Load Probability" method has been the most widely used by the utility industry.

The two important elements in calculating system reliability by this method are generation availability and load variability. These are generally called the generation (or capacity) model and the load model. These elements and the mechanics of the method are discussed in this section.

Generation Model

Each generator has a probability of being unavailable for operation due to an uncontrolled or forced outage. This probability of forced outage may be expressed as a percent of the time, such as two percent. The probability of being available for operation in this case would be 100 minus 2, or 98 percent. This "forced outage rate" for generators may be determined from a variety of sources, such as a unit's own history of operation, national experience with units of similar type, and/or extrapolation of data for the newer types and sizes of units. A reasonable range of forced outage rates for mature generators of various sizes and types would be from 0.5 to 8 percent.

The forced outage of a generator can be considered an independent event; that is, it is neither influenced by the forced outages of other generators, nor, in turn, does it influence them. The probability of the coincident occurrence of a series of independent events is the product of their individual probabilities. The following calculations develop the generation capacity availability for a very simple example of two generators, each rated 100 Mw, and each having a forced outage rate of 2 percent:

Probability of 200 Mw available=	(.98)	(.98)=	0.9604
Probability of 100 Mw available=2	(.98)	(.02)=	.0392
Probability of 0 Mw available=	(.02)	(.02)=	.0004
Summation of all alternatives =			1.0000

This tabulation represents the capacity model which would be used for the example in reliability calculations. The total probability of all cases is 1.0 per unit, or 100 percent.

For the probability calculations of system reliability, a generation or capacity model for the actual system is developed in a similar manner. Every possible combination of unit availability must be

considered, using the forced outage rates (or the corresponding availability rates) characteristic of each unit in each combination. The results are accumulated in a table of total available system generation and the associated probability of occurrence. For a larger example, which will be used later in a complete sample of calculation of system reliability, let us assume a system of four units—150 Mw, 125 Mw, 100 Mw, and 75 Mw. Each generator is considered to be in either of two states, "in" or "out". The number of combinational variations of (n) generators in either state is $(2)^n$. Then, for four generators, $n=4$ & $(2)^n=(2)^4=16$. All units are assumed to have a forced outage rate of two percent. The system of four generators would produce the following capacity model:

Capacity Model

Unit—Mw				Total capacity available (Mw)	Probability of occurrence
150	125	100	75		
In	In	In	In	450	......$(0.98)^4=0.92236816$
In	In	In	Out	375	$(0.98)^3(0.02)=0.01882384$
In	In	Out	In	350	$(0.98)^3(0.02)=0.01882384$
In	Out	In	In	325	$(0.98)^3(0.02)=0.01882384$
Out	In	In	In	300	$(0.98)^3(0.02)=0.01882384$
In	In	Out	Out	275	$(0.98)^2(0.02)^2=0.00038416$
In	Out	In	Out	250	$(0.98)^2(0.02)^2=0.00038416$
Out	In	In	Out	225	$(0.98)^2(0.02)^2=0.00038416$
In	Out	Out	In	225	$(0.98)^2(0.02)^2=0.00038416$
Out	In	Out	In	200	$(0.98)^2(0.02)^2=0.00038416$
Out	Out	In	In	175	$(0.98)^2(0.02)^2=0.00038416$
In	Out	Out	Out	150	$(0.98)(0.02)^3=0.00000784$
Out	In	Out	Out	125	$(0.98)(0.02)^3=0.00000784$
Out	Out	In	Out	100	$(0.98)(0.02)^3=0.00000784$
Out	Out	Out	In	75	$(0.98)(0.02)^3=0.00000784$
Out	Out	Out	Out	0	......$(0.02)^4=0.00000016$
					1.00000000

The probabilities above are for that exact amount of available generation shown, no more and no less.

Load Model

The load model that is used for the reliability calculations is developed to show the variability of daily peak loads on an annual basis. These load models are usually developed from historical records of daily peaks with adjustments made for future changes in characteristics. These load models may be quite complex, but a simple load model is used here to demonstrate their use. Eleven blocks of load are used to represent the whole range of daily peaks found in a year.

In the load model a cumulative probability table was developed which shows the probability that the load will be the value shown or higher.

Load Model

Load Blocks (Mw)		Probability of occurrences	Cumulative probability (probability load will be value shown or higher)
359	370	0.0012	0.0012
347	358	0.0085	0.0097
335	346	0.0384	0.0481
323	334	0.1105	0.1586
311	322	0.2107	0.3693
299	310	0.2614	0.6307
287	298	0.2107	0.8414
275	286	0.1105	0.9519
263	274	0.0384	0.9903
251	262	0.0085	0.9988
239	250	0.0012	1.0000
...	...	1.0000	......

Reliability Calculations

A capacity model which shows the probabilities for exact amounts of generation being available, and a load model which shows the probabilities that the load will be a certain level or higher, have now been developed. If the two models are matched up, the probabilities that the load exceeds the available generation can be found. Combining the ca-

pacity and load models to determine loss of load probability could just as easily be performed using a capacity model developed on the basis of the probabilities of availability of specific levels of generation or less, and a load model that had the probabilities of occurrence of an exact level of load.

The Reliability Model, shown in the following tabulation, is based on the coincidence of specific steps of generation being available and excess load occurring. These events (generation availability and excess load), like generator outages, are independent events, and the product of their probabilities is the probability of their coincidence. Columns 1 and 2 are the Capacity Model. For each level of available generation in Column 1, the probability that the load will be higher is taken from the Load Model and placed in Column 3. There is no load in excess of 370 Mw, and therefore, there is no excess load probability for generation availabilities of 375 and 450 Mw. The load is in excess of 350 Mw 0.97 percent of the time, and exactly 350 Mw of generation is available 1.882 percent of the time. The coincidence of exactly 350 Mw of generation being available and the load being in excess of 350 Mw is (0.0097 (0.01882) = 0.00018259 per unit of the time. Such calculations are repeated similarly for each level of generation availability.

Saturday, Sunday and holidays are normally omitted in the preparation of load models. The

Reliability Model

(1) Generation available (Mw)	(2) Probability this generation being available	(3) Probability that loads exceed capacity	(2) x (3) probability that load will be lost (i.e., load exceeds gen.) (4)
450..........	0. 92236816	0	0
375..........	0. 01882384	0	0
350..........	0. 01882384	0. 0097	0. 00018259
325..........	0. 01882384	0. 1586	0. 00298546
300..........	0. 01882384	0. 6307	0. 01187220
275..........	0. 00038416	0. 9519	0. 00036568
250..........	0. 00038416	0. 9988	0. 00038370
225..........	0. 00076832	1. 0	0. 00076832
200..........	0. 00038416	1. 0	0. 00038416
175..........	0. 00038416	1. 0	0. 00038416
150..........	0. 00000784	1. 0	0. 00000784
125..........	0. 00000784	1. 0	0. 00000784
100..........	0. 00000784	1. 0	0. 00000784
75...........	0. 00000784	1. 0	0. 00000784
0............	0. 00000016	1. 0	0. 00000016
Total Probability of Some Loss of Load.........................			0. 01735779

load is sufficiently depressed on these days so that there is no measurable contribution to the annual risk of load loss by their inclusion. Neglecting these days there are 250 load days per year on which the load model is based. Taking the probability of loss of load from the probability model, 0.01736, and multiplying by 250 gives the number of days per year load may be expected to be lost.

$$(0.01736(250) = 4.34 \text{ days/year}$$

The reciprocal of this number gives years/days, the measure of system reliability normally used in the technical literature on this subject.

$$\frac{1}{4.34} = 0.23 \text{ years/day}$$

The results of this example calculation indicate a level of system reliability which is far below any standard now used in this country. To improve the level of reliability, additional generators would be added to the capacity model, and calculations repeated until the desired reliability is reached.

Most companies use a far more sophisticated approach for the "Loss of Load Probability Method." Among the detail usually added are:

1. Much more detail in the load model, including probable deviations from normal due to weather and business cycle variations.
2. Scheduling of generation maintenance, which may be either subtracted from the generation model or added to the load model.
3. Effect of seasonal variation of generation output (e.g., changes in injection temperatures.)
4. Variation of generator forced outage rates as the unit matures.
5. Calculation of reliability of two pools simultaneously, including the effect of each on the other's reliability.
6. Analytical considerations of the effects of distances between generation units, distances between generation and load areas, and reliability of the transmission required to connect these units and areas together, and to make an overall functioning system of all these elements.

VARIABLES AFFECTING RELIABILITY

From the available experience gained through the use of probability mathematics to calculate required generation reserve, certain generalities have been observed which are worth noting.

Unit Size

Assuming all other variables, including forced outage rates, remain the same, when a unit is added which is of a size appreciably larger than the system's average, it will increase the required generation reserve. The new unit will roughly affect the reliability calculations in proportion to the square of its size. An 800 Mw unit would have four times the effect of a 400 Mw unit. This disproportionate effect is most noticeable when a very large unit is added to a system composed of small sized units. The initial installation of large units to a system will cause a sharp rise in reserve requirements. This effect will drop rapidly as further large units are added.

Forced Outage Rates

The exposure of a unit to failures such as boiler tube leaks and insulation breakdowns of generator windings is proportional to the physical lengths of these components, which are a function of unit size. In general, the larger the unit, the higher its forced outage rate (see Table 16). Also, higher steam temperatures and pressures increase forced outage rates due to higher incidence of boiler troubles. A new unit will also experience much higher outage rates during its break in period. The maturing of a unit to a level forced outage rate may take as long as six years. Hydro units, in general, have lower forced outage rates than thermal units of comparable size.

System Size

With all other variables constant, the percent reserve requirements will become smaller as the number of units increases. For example, a system with a load served by one unit would require a minimum of 100 percent reserves; if the load is served by two equal units; the reserve requirement would be 50 percent, and if served by three equal units 33⅓ percent.

Pooling

Interconnections have the effect of increasing the number of available units as well as system size, and therefore, reduce the percent reserve requirements. Generally, the larger a system becomes the smaller become the reserve benefits that will be realized by pooling. However, if unit sizes are large enough, reduction of reserve requirements by additional pooling would still be worthy of consideration by pools or systems of the 30,000 Mw size (Fig. 13). In general, the pooling of two systems will result in the smaller gaining the higher percent reduction in its reserve requirement.

TABLE 16

Forced Outage Rates of Base Load Units

Nameplate Rating (Mw)	Rate (%)
Existing Fossil Units:	
0–100	1. 5
101–300	3. 9
301–500	5. 5
Future Mature Fossil Units:	
600	5.8 to 7.8
800	6.7 to 9.4
1000	7.4 to 10.7
Future Mature Nuclear Units:	
600	5.1 to 7.2
800	5.8 to 8.7
1000	6.5 to 10.0
2000	10.0 to 16.0

Multipliers for Immature 600–1000 Mw Units (Both Fossil and Nuclear with Once Through Boilers)

Year of Operation	Units in service: Before 1975	Units in service: 1975 and later
1	2. 40	1. 60
2	1. 60	1. 33
3	1. 33	1. 18
4	1. 18	1. 08
5	1. 08	1. 00
6	1. 00	1. 00

Load Shape

Systems which have their high peak loads only in one season will have their major risk in that period. Maintenance outages, including refueling of nuclear units, will have little effect on reliability if they are scheduled in load valleys. Systems which have substantially equal peak loads in all seasons will have essentially equal risk of loss of load for all seasons. Their required reserve will not only be higher due to length of period of risk, but an extra component will be required to cover maintenance outages.

Trends

As systems with average size units between 100 and 300 Mw are adding new large units (800 to 1100 Mw), they are experiencing a rapidly rising percent reserve requirement. This is being mitigated

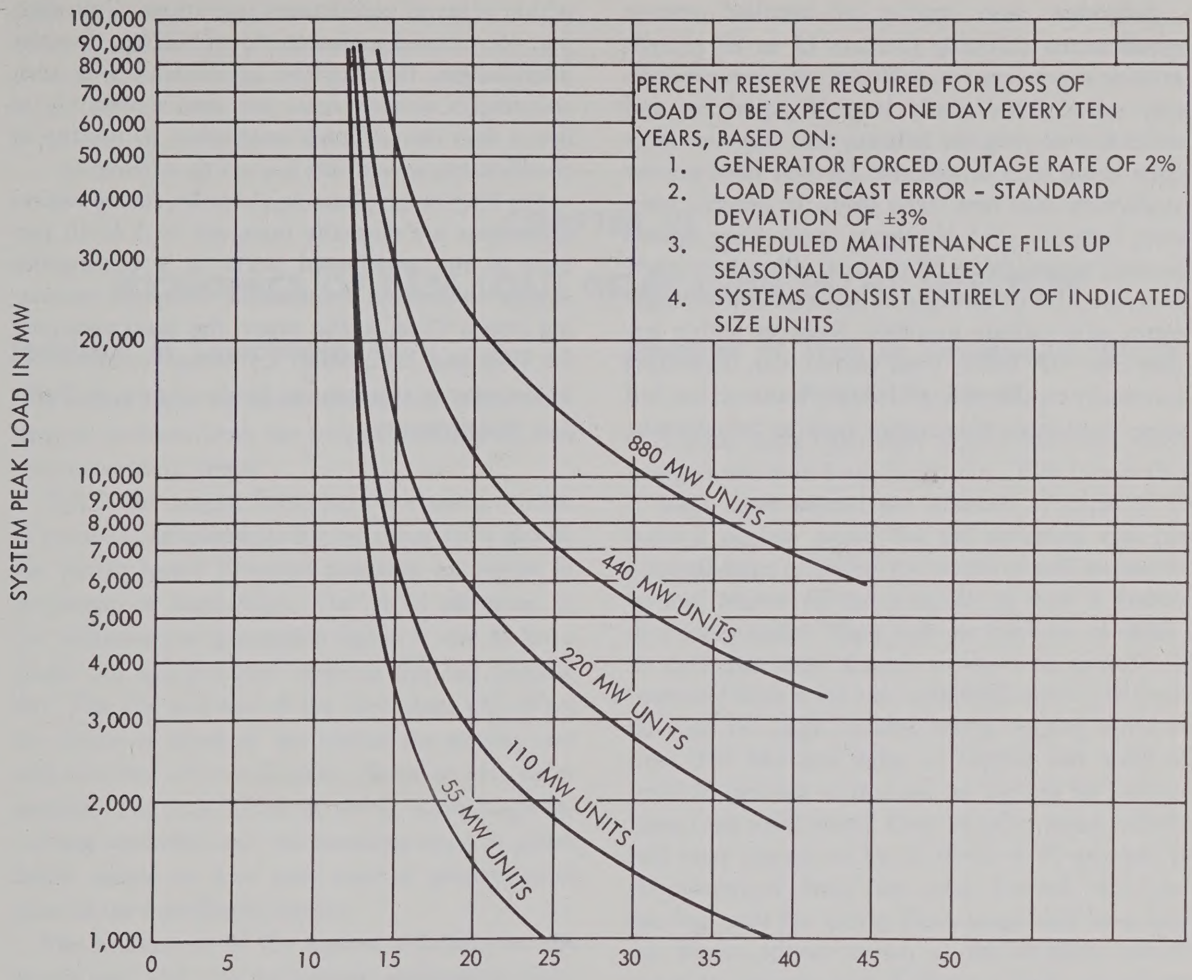


Figure 13

somewhat by a coincident increase in scope of interconnections and pooling. If unit sizes level off and systems and interconnections grow, the percent reserve requirement will take a downward trend. However, this downward trend could be reduced or even reversed by flattening of the annual load shape and by a continued upward trend in unit size. A flattened annual load shape could result from the balancing of summer cooling load with winter heating load.

In computing reserve requirements for the Northeast, each coordinating group uses some variation of the general principles discussed in the earlier portion of the Chapter, recognizing the trends discussed above and the reserve limits established by pools or other management groups. Reserves are generally determined utilizing probability mathematics in order to provide for a predetermined loss of load probability. Capacity models provide for cyclic scheduled generation maintenance, for seasonal variations in generation output, and for variations in forced outage rates due to degrees of maturity of units. Generally, the load models provide for deviations from normal due to probable weather and business cycle variations. Also, the effects of neighboring pools are in general, included in the calculations. The standard for loss of load probability currently accepted is one day in 10 years.

Individual area studies of installed reserve requirements currently indicate 15 to 20 percent as being representative. A 20 percent reserve margin may prove unnecessarily large if experience and technological progress indicate that the very large units being built or planned for will have greater availability than now seems likely. In general, however, systems in the Northeast are moving toward reserves approaching 20 percent, either from their own resources or through formal and firm arrangements with outside suppliers. Reserves within systems may vary widely from year to year, depending prrimarily on the timing of major construction, but these short-term fluctuations tend to be offsetting within areas of coordinated operations. Unit sharing, coordinated maintenance scheduling, diversity interchanges, firm transfer agreements, and other cooperative arrangements are used extensively to insure that reserve levels established by pooling or coordinating agreements are strictly adhered to.

For long-range planning purposes, future reserve allowances are normally increased by 5 to 10 percent of the anticipated peaks as a contingency against unforeseen construction delays or estimating errors. Thus, in this report the plans presented for 1980 and 1990 reflect a contingency allowance in the reserve requirement figures shown on Table 1 in the summary.

CHAPTER VI

ECONOMICS OF BASE LOAD GENERATING PLANT SELECTION

Problems of Comparison

A utility faces no more complex or more challenging problem than the proper selection of base load generating plants.

This is the largest investment the utility makes. It requires commitments five or seven years ahead, yet entails heavy financial penalties for errors in judgment or forecasting. The rapid advances in the technology of generation makes it wise to leave plans and specifications open to the last possible day. The site and size of the new plant will affect the design of much of the rest of the system, and will also bear on coordination planning with other systems. The intangibles of public acceptance involving aesthetics and environment must be given dollar values so they may have a proportionate place in the overall calculations.

The attainment of the highest reliability at the lowest cost, and with the greatest satisfaction to the community is a most exacting undertaking.

The factors that must be considered in the decision are so interrelated that a large variety of possible solutions must be individually costed out before a final selection is made.

It is, for instance, frequently not possible to choose directly between a nuclear plant and a fossil-fueled plant. The decision must be between a nuclear plant of the most economical size at the best site obtainable against a fossil-fueled plant of perhaps a different size at a different location. And entering into this decision are questions of air and thermal pollution, the future adapability of the plant to intermediate or peaking service, the trends, up or down, of nuclear against fossil-fuel costs, the comparative costs of fuel storage at the sites indicated (coal requires large areas with conspicuous handling equipment), and the effect on public relations of the adoption of an impressively modern type of equipment.

Selection of Type of Generating Facility

Nuclear Vs. Fossil

Nuclear units have high capital costs and lower energy costs than fossil-fired units. This means that it takes more capital per kilowatt of capacity to build a nuclear plant, but the operating cost per kilowatt-hour of electricity produced will ordinarily be less. Moreover, the economy of scale is greater in nuclear units: Their cost per kilowatt of capacity decreases more sharply as the total capacity is increased than is the case with fossil units. The capital costs for large nuclear plants ranging upwards from 500 Mw are today at capital cost levels of from 20 percent to perhaps as high as 60 percent more than fossil plants. One the other hand nuclear fuel costs appear to be at levels of 40 percent to 70 percent of fossil fuel costs. Overall, the total bus bar costs for energy from large high base load use plants appear to be, at the moment, pretty much in balance, with perhaps a slight advantage of the nuclear on total costs for areas having relatively high fossil fuel costs. There does not appear to be any reason to expect that the nuclear advantage will not be maintained or even increased as time goes on.

In general, companies with high money costs and high taxes will find it more difficult to justify the higher capital costs of nuclear units than companies with lower money costs and taxes. On the other hand, companies in high fossil fuel cost areas such as New England find the economics favor nuclear units because of their low energy costs.

In the case of fossil fuel, the relative merits of coal, oil and gas must be considered in all these relationships. Coal-fired plants have a higher capital cost than the others, because they require more land and more expensive fuel handling facilities.

Siting

In siting the plant, whatever the fuel, development costs, local taxes, proximity to load centers

now and in the future, cost of delivery to these centers, existing transmission lines, availability of rights of way for new lines and their public acceptance must be studied.

It might be economically desirable to build a generating plant a considerable distance from a load center if local taxes and site development were lower than the increased transmission costs. Existing plant sites and rights of way may be profitably used by a wise selection of unit sizes and transmission voltages.

Size

In general, the bigger the plant the lower is the cost of construction and operation per kilowatt of capacity and kilowatt-hour of energy. But the bigger the plant, the bigger must be the available reserves to replace it if it unexpectedly shuts down. In addition, capacity above the actual load demand ties up capital, may require additional transmission investment, and may restrict somewhat the decision on future generating and transmission additions.

On the other hand, installations larger than needed for load growth may be justified by the savings from retirement of older and less efficient units, by the more effective use of a site, by long-term sale contracts with other utilities or by coordination with an interconnected system. This last offers the great and growing opportunity for enjoying the economies of scale in generation.

Timing

Timing is critical. It is governed primarily by load requirements and reliability standards. But it is complicated by the increasingly longer lead time now required, as well as by the necessary balancing with other generation—base load, intermediate or peaking. Retirement of older units and sales to other utilities can advance the construction date.

Economics and Financing

Some elements of the problem can be reduced to reasonably assured mathematical analysis. Total production costs of a particular plant can be divided into two classes, fixed and variable. The variable costs vary with the level of generation and include the non-fixed portion of operation and maintenance as well as fuel.

The fixed costs include the costs of money, depreciation, taxes, insurance and a portion of the operating and maintenance costs. These have to be met no matter what the level of generation may be, and even when the plant is idle. If the plant is operated at high capacity most of the time, the fixed costs are divided among a great many kilowatt-hours of produced energy. Peaking plants on the other hand are operated for relatively small periods of time, and their fixed charges are divided among much fewer kilowatt-hours of produced energy.

Generally, the original cost of a project for all types of utilities is financed in part by internal funds as well as by new capital.

The charge for depreciation is the amount to be put aside annually so that the accumulated sums will recover the original cost of the facility at the end of its expected life, less any sum recovered by salvage. These funds are usually invested in new plant facilities in the case of investor-owned utilities, and regulatory authorities generally deduct the reserve thus created from the "rate base." That is, the reserve is not considered a part of the total investment of the utility for purposes of figuring allowable earnings.

The Internal Revenue Code permits various methods of figuring the annual depreciation charge for tax purposes. This may be an equal annual amount over the life of the facility, or it may be a larger amount in the early years and lesser in the later years. But if tax rates do not change, there is no difference in the total recovery over the years, and no difference in the total tax incurred although the deferral of taxes provides a monetary benefit because of the interest saving. The four methods allowed are:

1. The straight line method.
2. The declining balance method, using a rate not exceeding twice the rate which would have been used had the annual allowance been computed under the straight line method.
3. The sum of the years' digits method.
4. Any other consistent method productive of an annual allowance which when added to all allowances for the period, commencing with the taxpayers use of the property and including the taxable year, does not, during the first two-thirds of the useful life of the property, exceed the total of such allowances which would have been used had such allowances been computed under the declining balance method.

A taxpayer may at any time change from the

declining balance method to the straight line method, but a change is not allowed in methods 1, 3. and 4 without prior permission.

The tax element of the fixed charges is the total of yearly taxes levied on the utility by local, state, and federal governments which depend on the original cost of plant facilities either directly or indirectly.

There are many other factors that must be considered in economic analyses and comparisons of alternative plans. They are, however, too involved to warrant discussion in this report. For a complete treatment of the subject, the reader is referred to the book entitled "Profitability and Economic Choice," by P. H. Jeynes. (Iowa State University Press, 1968.)

CHAPTER VII

PATTERN OF BULK POWER TRANSMISSION IN THE NORTHEAST

General

The three areas included in the NERAC region are now interconnected at 230 Kv between New York and PJM and 345 Kv between New York and New England. A 500 Kv tie between PJM and New York was planned for service in May 1968, but right-of-way problems have delayed its expected in service date to December 1969. More EHV ties between these areas are envisioned in the 1970–1990 period, as indicated on Figures 2 and 3, in the Summary at the beginning of this report.

Major generation developments in these three areas are shifting from fossil-fueled units to large nuclear units. A number of nuclear installations have been or are being planned in all three areas for service in the 1968–75 period. More EHV transmission installations will be required as a result of these generation developments.

Preliminary results of long-range studies have indicated continued expansion at 345 Kv and 500 Kv in the near term years. For the far term development it appears that several factors will dictate the use of a higher voltage of at least 765 Kv. These are:

1. A requirement to increase generating unit and generating plant size to obtain economies of scale and maximize usage of a limited number of good generating sites. Progress in the above direction infers the need of a strong transmission system; to deliver large blocks of power under both normal and emergency conditions, to make possible sharing of reserves which are an integral factor of the large unit philosophy, and to absorb the stress of loss of a large unit or plant with no impairment of system integrity.
2. To achieve maximum right-of-way loading on the limited right-of-way available.
3. To achieve economic transmission capacity. For example, 765 Kv is capable of transmitting from four to six times as much power as 345 Kv over comparable distances, while 765 Kv construction is approximately twice the cost of 345 Kv. Therefore, cost per Mw transmitted is reduced by a factor of 2 or greater with use of the higher voltage.
4. To coordinate with plans for development of regions adjacent to the Northeast.

The operating groups of the utilities in the Lake Ontario and Lake Erie regions have formed a joint study committee known as the Great Lakes Eastern Operating Study Committee (GLEOS) to investigate the effects of the new interconnections between the Michigan utilities and the networks to the South. The Committee is composed of representatives of the Northeast Power Coordinating Council, the Mid-Atlantic Area Coordination group, and the East Central Area Reliability Coordination group. The Hydro-Electric Power Commission of Ontario participates as a member of NPCC. The GLEOS effort is planned to be a continuing one and represents a noteworthy example of an interregional coordination activity. The major investigations to date have been directed toward analysis of conditions which might be experienced if planned generation and transmission construction schedules cannot be met.

As presently operated (summer 1968), the transmission system of the southern peninsula of Michigan is connected to the remainder of the United States via the transmission system of the Hydro-Electric Power Commission of Ontario in Canada. This arrangement will be reinforced in 1969–70 when 345 Kv ties will be extended from Michigan to interconnect with the United States systems to the south.

Among the advantages of these ties will be—that they effectively close a loop, thus eliminating what can be broadly termed a radial system, i.e., today the northeastern United States (north of the south boundary of New York State) is radial to the rest of the United States, in turn Canada is radial to the United States, and in turn Michigan is radial to

Canada. Thus closing the loop provides additional paths for normal, economy, diversity and emergency interchange; and these additional paths add to the systems' capability to sustain loss of a large generating unit or units in Michigan, Ontario or the northeastern United States. The instantaneous inertial power flow following the loss of a large unit in Michigan, Ontario, or the northeastern United States will flow over both routes into the region instead of over the present single route via the New York State-PJM ties.

Detailed descriptions of transmission plans for each of the Region I study areas are contained in the following sections. Figure 14 is a schematic diagram of the existing and contemplated EHV transmission system. Mileages by voltages classes for the major primary lines are shown on Table 17.

Area A—New England

The major utility systems of each of the six New England states are presently embarked on a large-scale coordinated power supply development program, comprising economical large-size generating units interconnected by an extensive 345 kilovolt backbone transmission network, known as the Big-Eleven Power Loop. This program is scheduled for completion by 1972 and is expected to be a major factor in counteracting rising power production costs in New England. The eleven generating plants from which the program derives its name, range in size from 350 megawatts to 1,500 megawatts, and comprise nuclear, fossil fuel and pumped storage plants.

The backbone 345 Kv transmission network will form a loop serving major substations accessible to points of heavy load concentrations. The 345 Kv transmission systems will extend from the tie with the Pleasant Valley Substation of Consolidated Edison Company in southeastern New York State, through the heavy load areas of central Connecticut, interconnecting with the 600 Mw nuclear generating units of the Connecticut Yankee Electric Company. The 345 Kv transmission will then extend northward and eastward to the heavy load areas of Massachusetts, and then to New Hampshire and Maine, interconnecting with the 855 Mw nuclear generating plant of the Maine Yankee Electric Company. Returning from the Maine nuclear unit across southern New Hampshire to the southeastern corner of Vermont, where it will interconnect with the 540 Mw nuclear generating plant of the Vermont Yankee Nuclear Power Company, the 345 Kv transmission then will turn southerly again into Massachusetts to interconnect with the 1,000 Mw pumped storage plant of Northeast Utilities, Inc. From this point the 345 Kv transmission will extend both southerly and westerly, closing the loop within New England, and also closing a loop through the upstate New York systems by a 345 Kv interconnection near Albany, New York. A complementary 345 Kv loop will also be formed by connecting the Millstone plant of Northeast Utilities with the main backbone in central Connecticut and eastern Massachusetts. The other large generating plants included in the Big-Eleven Power Loop Development will be interconnected with the main loop

TABLE 17

Northeast Regional Advisory Committee—Transmission Lines and Average Costs

Voltage (KV)	Total Miles of Line			1968 Estimated Cost per Mile	
	1970	1980	1990	Right-of-Way	Line
New England:					
345	767	1, 950	2, 390	$30, 000–$60, 000	$50, 000–$85, 000
765			350	$40, 000–$80, 000	$200, 000
New York:					
345	445	1, 155	1, 570	$10, 000	$100, 000–$220, 000
500	5	5	5	$50, 000	$200, 000
765			870	$75, 000	$200, 000
PJM:					
500	870	1, 600	2, 200	$10, 000–$100, 000	$120, 000–$200, 000
765			100	$10, 000–$100, 000	$200, 000
Northeast Region:					
345	1, 212	3, 105	3, 960	$10, 000–$60, 000	$50, 000–$220, 000
500	875	1, 605	2, 205	$10, 000–$100, 000	$120, 000–$200, 000
765			1, 320	$10, 000–$100, 000	$200, 000

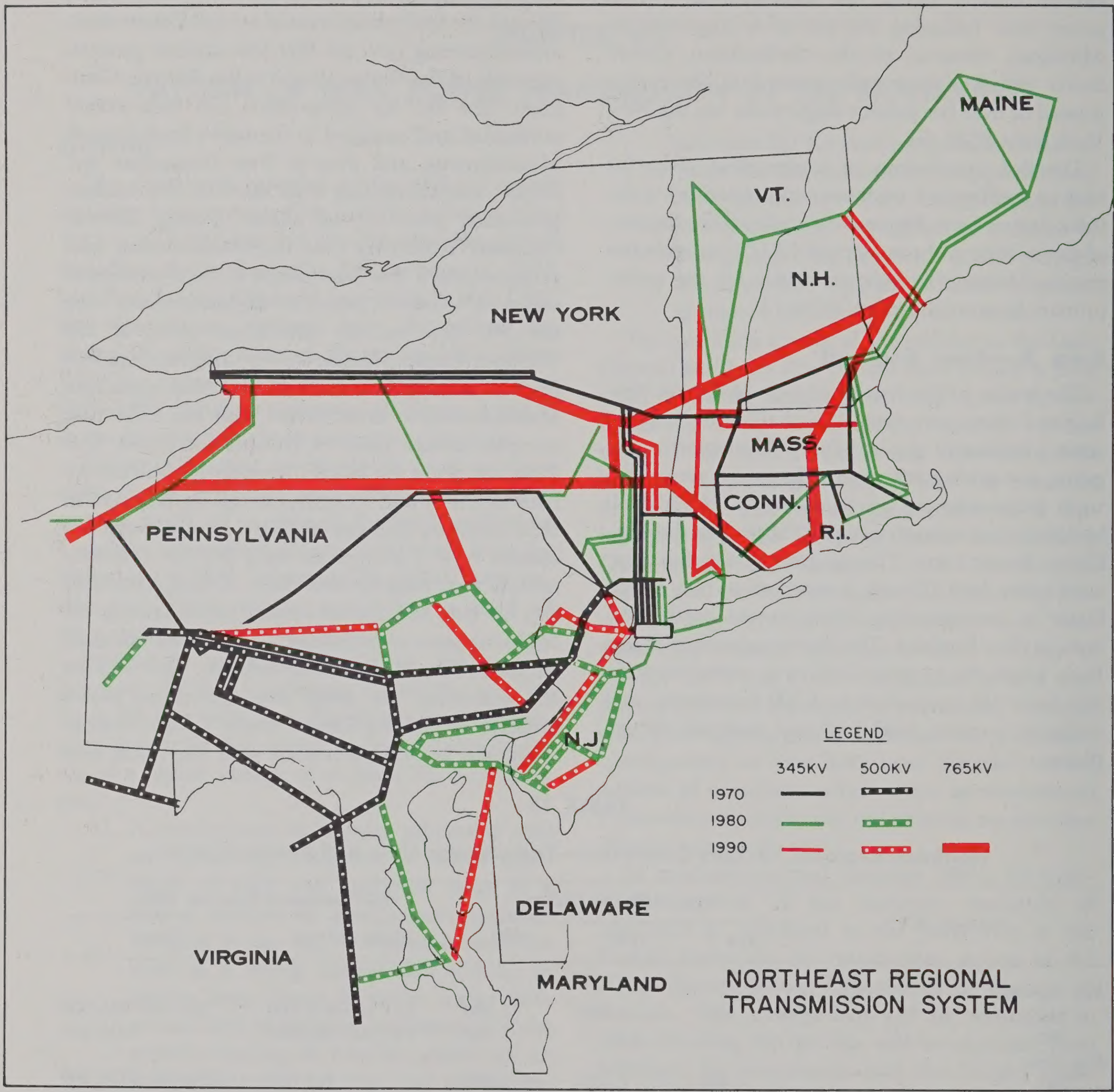

MAINE
VT.
N.H.
NEW YORK
MASS.
CONN.
R.I.
PENNSYLVANIA
N.J.
LEGEND
345KV 500KV 765KV
1970
1980
1990
DELAWARE
VIRGINIA
MARYLAND
NORTHEAST REGIONAL
TRANSMISSION SYSTEM

Figure 14

through 345 Kv ties which will comprise complementary loops when other major load areas and large generating stations are similarly interconnected as the loads continue to grow.

Development of the Big-Eleven Power Loop is being planned jointly by the principal utility systems of New England, and is being coordinated internally and with the utility systems of New York, to provide for all of the utility systems of the Region the advantages of reliability and economy from coordination of generation and reserves on a large scale. Extensions of this 345 Kv system are already being studied which will provide further improvements to reliability of supply, forming complementary loops with the underlying 230 Kv and 115 Kv transmission and eventually closing these loops at 345 Kv as the loads continue to grow and other large generating units are installed.

As generating unit sizes increase and opportunities develop for interchange of larger blocks of power with other power producing areas, 765 Kv transmission interconnection between the 345 Kv systems of New England and the systems of other areas will be developed. The 765 Kv transmission will extend from Maine through the eastern Massachusetts area into central New York State and beyond, eventually forming loops through southern New England, with some ties extending from these loops, developing in a manner similar to the present development of the 345 Kv transmission.

Area B—New York State

New York State, due to its diversity in population density and to its geography, offers some problems in transmission expansion during the decades of the 1970's and 1980's. Transmission will have to be built for two separate and distinct purposes: (1) to increase reliability through the pooling of reserves and the exchange of emergency power and (2) to transmit large blocks of power from source to load centers within the framework of an over-all system designed for optimum economy.

The present 345 Kv transmission system will serve adequately through 1970. Prior to 1980 it will be suitably expanded. The growth of the load in the western part of the State which will absorb the power generated at Niagara and new generation added in the eastern part of the state will relieve the relatively heavy west to east flow on the cross-state 345 Kv system.

As the overall load grows during the 1980's, it will be necessary to increase the transmission capability in the State. It is contemplated that a 765 Kv transmission system will connect with New England. This system would be extended across the State to Niagara where it would enter Ontario and eventually connect with the 765 Kv system in Michigan. It would also be strongly linked to the PJM system both in the central and western parts of the State. This would give New York State 765 Kv interconnections with systems to the south and west, and thereby, increase its ability to absorb a major system disturbance successfully. This 765 Kv system would also enable the exchange of emergency power, not only between different areas of New York State but also with the adjoining areas of New England, PJM, and Ontario, thus allowing an even greater degree of pooling of reserves with neighboring power systems.

The second function of transmission during the 1970's and 1980's will be the transportation of electric power from the site of generation to the load. Due to problems associated with air pollution and the difficulties in siting nuclear units, it is not contemplated that generation can be built within large metropolitan areas prior to the end of the 1970's. Therefore, it seems probable that extensive transmission will be built to transport power from outlying generating sites to these large metropolitan areas. Since it is difficult and in some cases impossible, to obtain overhead rights-of-way in the vicinity of these metropolitan areas, it seems probable that much of this transmission will be underground where technically and economically possible. It seems that DC transmission should be considered as a possible alternate means of transporting these large blocks of power underground into the metropolitan load centers.

Area C—PJM Interconnection

The initial 500 Kv transmission grid associated with the Keystone mine-mouth project is being completed. A second mine-mouth plant at Homer City in 1969 and 1970 will be connected by two 345 Kv circuits northward, one to Binghamton, N.Y. and the second to Erie, Pennsylvania. The 500 Kv system will be further expanded in the 1970–71 period as a result of the installation of the Conemaugh mine-mouth project. This EHV network will facilitate not only the delivery of the mine-mouth generation to the east, but also will about double the interchange capacity between PJM and the adjoining pools (New York State,

East Central Area, Carolinas-Virginias Power Pool).

As the system load grows, a larger portion of the output from the mine-mouth plants will be absorbed by loads in western and central portions of the PJM system. However, increasing interpool power interchange requirements are expected to call for more west-east EHV transmission in future years for the purpose of improving system reliability and operating economy.

Presently, a number of large nuclear projects with units in the 800–1000 Mw range are being either constructed or planned for service in the 1971–75 period in the PJM area. Most of these units are expected to utilize 500 Kv transmission, either partly or wholly, as their outlets. The advantages for EHV are generally determined by the following factors:

1. Overall economic choice.
2. Less right-of-way requirements per megawatt of capacity.

One of the major EHV expansions in the 1971–75 period may well be the extension of the 500 Kv transmission to the Washington, D.C. area and southward to link with the VEPCO's 500 Kv system. This will further integrate the Baltimore-Washington area with the rest of PJM and increase the north-south interchange capabilities in the PJM system.

Looking beyond 1975, it is anticipated that the base-load unit size will increase above the 1000 Mw range, although the rate of unit size increase may be slower than in the 1965–75 period. However, installation of large nuclear units closer to the densely populated areas are also expected to become acceptable after 1975. Shorter distance of haul of power may be the future trend. It is therefore concluded that the major EHV transmission system in the PJM area will remain as 500 Kv through 1990.

To recapitulate, for the period from now to the middle of the 1970's plant locations and the corresponding transmission interconnections are already largely committed. These reflect heavy use of mine-mouth coal burning plants and relatively strong (500 Kv) transmission ties from the plants in the Pennsylvania and northern West Virginia coal fields to the eastern seaboard to deliver the plant output to the load centers.

Subsequently, it is expected that there will be an increasing trend toward building nuclear plants as near as possible to the load centers. These will tend to be concentrated along the east coast from Boston to Washington, with secondary concentrations along the shores of Lake Ontario and Lake Erie. Pumped storage plants to provide economical peaking tend to be located somewhat inland in the more rugged geographic areas where substantial elevation differences may be found.

As loads grow and plants are increased in size, additional transmission capacity is required to move the power from the generation sites to the load centers. On the average, the generation sites will be closer to the load centers, so that, under normal conditions, the loading of some transmission lines may be changed so as to have more capability to transit emergency power. The possibility, or even probability, must be faced that the occasional loss of one or more very large units, and probably several large units in a single or perhaps two adjacent plants will occur. With such an occurrence, if system break-up is to be avoided, there must be sufficient transmission capacity to bring in adequate replacement power. Regardless of the nominal amount of spinning reserve available actual power demands during the first two or three seconds must be supplied from surrounding sources in amounts generally proportional to the inertias of the individual sources and inversely proportional to their effective electrical distances from the point of deficiency. If the nearby sources are relatively small, and the electrical distances to other sources are too great, i.e., the transmission interconnections too weak, the immediate area suffering the power deficiency will pull out of step with the interconnected system thus creating the potential for a power interruption. To illustrate, the concentrated load area of New York City is expected to have a peak load of about 20,000 Mw by 1990, and perhaps to be served in part by several units of as much as 2,000 Mw of capacity each, probably with two or more units in the same plant. Thus, the loss of 4,000 or 5,000 Mw of generating capacity practically at the load center is not impossible. It is evident that transmission with a short-time capacity of about 5,000 Mw more than that normally in use would be needed to handle the emergency flows that would occur until generation could be readjusted.

The 230 Kv Transmission Network

Underlying the EHV (765 Kv–500 Kv–345 Kv) network existing and proposed in the Northeast Region is an extensive transmission system of 230 Kv and lower voltages. This large capacity grid is a

significant factor in the movement of power through the region and achievement of desired levels of reliability. As of June 30, 1968, there were some 4,700 circuit miles of 230 Kv transmission in the region. Study Area C (PJM) with about 2,930 circuit miles accounts for 62 percent of the total; Area B (New York) with 1,150 miles, 25 percent; and Area A (New England) with 630 miles, 13 percent. Until the advent of EHV, beginning with the introduction of 345 Kv in New York, the 230 Kv circuits constituted the backbone transmission for most of the region.

In addition to existing 230 Kv facilities, about 1,300 circuit miles were under construction or authorized as of June 30, 1968, practically all in Area C. Undoubtedly, there will be future additions as needs dictate. While emphasis in utility planning of bulk power supply is on EHV, sub-EHV transmission continues to be a major consideration in systems optimization with respect to adequacy, quality and economy of supply in all parts of the region.

D.C. Transmission

The application of HVDC transmission has received much attention in the past few years. The primary advantages of HVDC transmission over AC are:

1. Lower cost per KVA for the underwater or underground cable or the overhead lines.
2. Reduced right-of-way requirements.
3. No increase in AC system short-circuit duties.
4. Accurate control of power flow reducing power surges and improving system stability.
5. Non-synchronous tie between systems.

However, there are also a number of disadvantages to the use of DC transmission. They are:

1. High cost of the converter-inverter equipment.
2. Questionable dependability of the converter-inverter equipment.
3. Operating complexities of multi-terminal circuit.
4. Problems of parallel operation of AC and DC transmission systems.
5. Heavy reactive requirements at receiving terminals.
6. Large land requirement for terminal stations.

Up to the present, d-c appears to be confined to some limited use for point-to-point delivery of a large block of power, either for a long distance or for under-water crossing. The approximate break-even point between d-c and a-c is in the order of 400–500 miles for overhead lines and 30–60 miles for cable circuits. The mercury-arc conversion equipment costs now about now about $20–30/Kw. Presently much research work is in progress to develop large-capacity silicon-controlled and similar-type rectifiers. It is expected that equipment of this type will eventually bring conversion cost down and thus improve the competitive position for d-c transmission.

In the Northeast Region, it is our estimate that some of the HVDC in the 1980–90 period might be desirable. Its use may be confined in general to the following applications:

1. Transmission from generation to metropolitan areas.

   With increasing difficulties in installing the necessary amount of generating capacity and acquiring transmission rights-of-way in the Boston-Washington megalopolis, d-c transmission could offer advantages over a-c in some cases because of the d-c capability of delivering more power over a confined right-of-way or via an underground or underwater cable.
2. Inter-system ties.

   Because of the peculiar characteristics of of its power systems and the already existing EHV grid, the Northeast Region is not expected to require long-distance EHV inter-system ties. Short distance d-c ties might be useful in the highly compact and developed systems in order to:
   a. Reduce short-circuit contribution to each system from the other, and
   b. Reduce the power surge problems during major system disturbances.

Aesthetics

Much has been written on the environmental and aesthetic problems facing the utilities today. The utilities are aware of these problems and are meeting them as rapidly as economically practical.

There is a wide disparity of economic, social and aesthetic costs and benefits when considering underground vs. overhead transmission lines. There are areas, primarily in and near high population centers, where underground transmission is an absolute necessity. As population centers grow, more underground transmission will be required.

In rural or areas of low population density, economics overwhelm aesthetic benefits of underground transmission by a wide margin. This is not to say that utilities should ignore aesthetics. Steps should and are being taken to improve and modify the appearance of overhead transmission lines. Such improvements and modifications might include the following:

Placement of structures, avoiding hill crests, settled, recreational, potentially developing, and congested areas.

Utilization of natural terrain to camouflage or make towers and lines inconspicuous.

Alignment of structures for pleasing effect.

Screening rights-of-way where roads are crossed, or in open view areas.

Apply aesthetic right-of-way landscaping and chemical treatment of shrubs and vegetation.

Selection of colors, tower styles, etc., which have high consumer acceptance.

Protect wild life and recreational areas.

Utilize rights-of-way for public recreational activities.

Keep to a minimum the amount of right-of-way clearance.

Because of the large cost differential between underground vs overhead transmission, the utilities and the customers must face this problem in a realistic and meaningful manner.

CHAPTER VIII

COORDINATED PLANNING, OPERATION, AND DEVELOPMENT

Introduction

Power development in the Northeast has been greatly influenced by large concentrations of population and industrial development. As power demands increased, new technology was developed and adopted. The utility industry was faced, as all other industries were, with integrating new techniques and technology with established equipment and procedures.

As the size of the electric system increased, savings could obviously be obtained by use of larger generating units, higher transmission voltages, pooling, and diversity between areas. Reliability could also be improved by strengthening interconnections between systems.

Massive interruptions that occurred in the Northeast have greatly influenced the thinking of system planners and designers, particularly in the development and adoption of criteria aimed at preventing a cascading outage. Also, area coordination organization to facilitate operation during emergencies, communication equipment and standby emergency generation have been added to an already sophisticated system.

Because work stoppages, legal interventions, and other procedural delays have been encountered in a high percentage of all recent power projects, allowance for these probabilities must be factored into lead times for the future. This adds a new dimension to coordinated planning and development, to the establishment of reserve margins, and to the techniques of coordinated operation during periods of generation and transmission nonavailability.

Historical Developments

Joint planning between pools in the region has been practiced for many years on a scale appropriate to the situation then existing. In the early years most intercompany planning activity was concentrated on developments within each of the three pools, as described below under separate headings. However, planning on what is now an inter-pool basis began many years ago.

Joint planning in the region covered by the NERAC report has been practiced for many years on a scale appropriate to the situation then existing. For example, in the 1930's a series of 34.5- and 115 Kv ties were added. The then existing ties and other interconnecting facilities have been used since 1951 for pooling of reserve capacity, interchange of economy energy, and coordination of maintenance programs between systems operating in New York and PJM.

In the early 1940's, in connection with the war effort, Consolidated Edison Company and Public Service Electric and Gas Company carefully studied several alternate 138 Kv ties between their systems. Although none of these was established (because of small diversity benefits, extremely difficult short-circuit current problems, and high costs) a foundation was laid for cooperative studies between these organizations. In 1963 a 138 Kv mutually beneficial tie between the two companies across the Arthur Kill was established and in 1968 it was converted to 230 Kv operation.

The NYPP and PJM companies cooperated very closely in planning the EHV interconnection between Branchburg and Millwood. This line, in conjunction with seven underlying ties between the two pools and the Homer City-Oakdale line, will make available to NYPP and PJM essentially all of the benefits of full coordinated planning that would be available in the late 1960's and early 1970's.

In consideration of the requirements imposed by rapid technological advance, complicated by expanding human and environmental problems, the utilities in the Northeast have already instituted or are in the process of developing additional interrelated mechanisms of coordination between utility-entities, designed to cope with a wide range of contingencies.

The Northeast Region has a long history of coordination of operation and planning that has led

over the years to the formation of: New England Power Pool (NEPOOL)[1]; New York Power Pool (NYPP); Pennsylvania-New Jersey-Maryland Interconnections (PJM); Northeast Power Coordinating Council (NPCC); and, Mid-Atlantic Area Coordination Group (MAAC). Each of the three power pools and two coordinating agencies are discussed subsequently.

The existing coordination and pooling agreements in the Northeast are sufficiently flexible to permit the expansion of their membership. The Northeast Power Coordinating Council and Mid-Atlantic Area Coordination Group agreement specifically permit other systems to apply for membership provided that their systems have a significant effect on the reliability of the bulk supply system of the area. In June 1968 Burlington Electric Light Department, a municipal serving the largest city in Vermont became a member of Northeast Power Coordinating Council.

The systems sponsoring the New England Power Pool, and the members of the New York Power Pool and the PJM Interconnection provide approximately 97.3 percent of the total energy production in the Northeast Region, and they directly serve approximately 95.8 percent (in Kwh) of the total regional loads. The remaining 4.2 percent is served by 63 investor-owned utilities, 190 municipals and other publicly-owned systems and 30 REA Cooperatives. The electric systems that are not members of a power pool are relatively small. In 1967, the largest unaffiliated investor-owned system had a peak demand of 162 Mw, the largest unaffiliated publicly-owned system had a peak demand of 50 Mw and the largest REA Cooperative had a peak demand of 72 Mw.

Except for a few completely isolated systems, non-pool members with generation participate in varying degrees of coordination with larger neighboring systems. Of these smaller enterprises a few rely entirely upon their own generation, including reserve requirements, with little or no use of interconnections except during emergencies. A few others share capacity reserves and participate in economy energy transactions with neighboring systems. The remainder of these small systems with generation have negotiated a variety of arrangements which fall between these two limits. When NEPOOL goes into operation, it is expected that small systems will have the opportunity to purchase capacity from large generating units planned to meet New England's total load growth and to carry capacity reserves determined in the same manner for all electric utilities in New England.

Longer-range plans and generation additions have been based on further joint planning. It is anticipated that full benefit from exchanges of power, reduction in reserve, and optimum unit size will be achieved through increased coordination as opportunities become available in the future.

Evolution in the area covered by NERAC has been toward the creation of three large pools (NEPOOL, NYPP, and PJM), with full coordination within each pool and close coordination with all adjacent pools, not merely among these three.

It is by no means axiomatic that "full" (as contrasted with "close") coordination between the three NERAC pools is a desirable social or economic goal. Reflection on the realities of power pooling suggests that there is some optimum size for a power pool. The benefits of system interconnection and coordination (power pooling) are well-known and amply documented:

1. Lower installed reserve requirements.
2. Ability to install larger generating units.
3. Lower spinning reserve requirements.
4. Ability to interchange economy energy.

The penalties have not been given the same emphasis, but they do exist:

1. Increase transmission requirements.
2. Organization complications.
3. Larger area to be affected by system disturbances.
4. Complexity of operation.

As the electrical size of a power pool increases (say, by additional interconnection and agreements), the incremental benefits gradually become smaller and the incremental penalties become larger. Thus, some optimum size exists.

The three pools in the area covered by NERAC are all within the 15,000- to 30,000-Mw range which has been indicated [2] as the optimum pool size for conditions prevailing in this section of the country during the early 1970's. Whether this will continue into the 1980's depends upon trends in the influencing factors, listed above, which are very difficult to forecast.

[1] In the final stages of formation.

[2] CIGRE Paper 32–09 (1968), Relationship Between Pool Size, Unit Size, and Transmission Requirements. J. A. Casazza and C. H. Hoffman.

These three pools are already well-coordinated internally, with each other, and with neighboring systems. The goal for the foreseeable future is not to seek in the Northeast one monolithic "fully-coordinated" pool in which the committee structure would be unmanageably large, but rather to promote ever-closer coordination within units of viable size with close—but not full—coordination with all neighboring pools. In particular, PJM's relationship with the systems to the west and south, systems which like PJM now have 500 Kv as their backbone transmission voltage, should be at least as close as its relationship with the 345 Kv backbone systems to the north and east.

In recent years many planning studies have been conducted between adjacent pools through interpool task forces. This has led to the installation of new interarea ties which has resulted in the development of a stronger and more reliable transmission system.

The transfer capability between pools has increased, and this has enabled each pool to reduce its generating reserve capacity below what would otherwise be required and to increase economy interchanges. Further coordinated planning studies are expected to verify the need for specific transmission and interconnection facilities of the general scope and scale depicted in Chapter VII, and on the Northeast Regional Transmission System map (Figure 14).

Numerous joint planning studies are now in progress among the three NERAC pools and between them and neighboring systems. The results of many planning activities in New England and New York are tested by the Northeast Power Coordinating Council (NPCC). An NPCC–PJM study group is working on long-range plans affecting those two regions and another very active interregional study group is concerned with coordination of plans of PJM and adjacent systems in the ECAR and CARVA areas. In this way a very close coordination of plans is being accomplished without the paralyzing effect of trying to have all systems represented directly on all committees.

The effect of the ties between pools has been recognized for many years in capacity planning studies. The effect is computed in terms of each pool's capacity benefit which results from the pooling of large systems. These benefits then result in a reduction of each pool's installed reserve requirement.

The projected forecast of generating capacity requirements is based on a continuance of this cooperation and communication between adjacent pools. Benefits between pools will continue in the future and will be facilitated by the formulation of new agreements such as the forthcoming NYPP–PJM agreement. Forthcoming agreements between coordinating organization will further improve coordination of reliability matters.

Future Patterns

It is difficult to forecast the future pattern of coordination. If only technological factors were to be considered, some of the present enterprises would be regrouped into larger but fewer organizations. Outright merger or consolidation is one way for this to take place, but whether the social and economic climate will tend to promote such action is difficult to foresee. Many, if not most, of the advantages of scale can be achieved by pooling, but this is truly an evolutionary process because of the communications problems inherent in this type of relationship.

It is interesting to note that the first affiliation since the Utility Holding Act occurred in the Northeast, between Connecticut Light & Power, Hartford Electric, and Western Massachusetts Electric to form Northeast Utilities. This affiliation now includes Holyoke Water Power Company. Recently Boston Edison, New England Electric, and Eastern Utilities Associates have announced plans to merge into a new enterprise to be known as Eastern Electric Energy System. Merger of Community Light and Power Company into Central Vermont Public Service is also in the implementation stage. No other mergers or affiliations have been announced in the Northeast Region.

In a continuing effort to optimize bulk power supply economies and to achieve increasing standards of reliability, coordinated planning and development has been extended over broader geographic and electrical load areas. As technological improvements continue in the development of generator unit sizes, EHV transmission, digital computers, communications, and in other aspects of power supply technology and methodology, the factors influencing optimum pool size in the Northeast Region, and the relationship among coordinating organizations, will continue to be reviewed and evaluated.

Reliability

A major focus of electric utility executives, planners, and system operators has always been, and will continue to be, to provide reliable electric service. Reliability is neither a new problem nor a new need. Neither is it a new objective of the industry.

Reliability of a bulk electric power supply system is measured by the availability of a continuous and uninterrupted supply of electric power. Our highly industrialized society has placed increased dependence on continuous uninterrupted service, the loss of which creates ever increasing hardships, especially in densely populated metropolitan areas.

Outages of individual components such as a generating unit, transmission line, transformer, or circuit breaker should not result in widespread interruption of service if the system is properly planned, designed, and operated.

The inherent reliability of a system is also increased by properly planned and coordinated pooling among neighboring areas with adequate interconnected transmission capable of withstanding severe system disturbances.

The more important principles involved in the planning and design of a system providing a high degree of service reliability are:

1. Generation and transmission should be planned on a coordinated basis providing sufficient reserve margins, over and above the normal energy generation and transmission functions, to allow for scheduled and forced outages and other abnormal contingencies.
2. A proper balance should be maintained between generating unit and station sizes, system load, and transmission voltages and capabilities.
3. Planned switching arrangements, relaying, and protection schemes should be evaluated to minimize hazards and assure system reliability.
4. Power flow, stability, and other related studies should be carried out regularly on a coordinated basis covering current operating conditions.
5. Power flow, stability, and other related studies should be carried out covering future system performance.
6. Power flow studies of steady state conditions should be examined under both normal and abnormal conditions representing reasonably foreseeable contingencies of transmission and generating equipment outages.
7. Transient and post transient stability studies should be carried out to examine the impact of severe faults or major power swings at all critical locations on the network.
8. Where there are inter-ties between coordinated areas, there should be an exchange of plans and system performance studies should be carried out between such areas.
9. To the maximum extent practicable, system plans should assure a reasonable distribution of generation and interconnection capability within the coordinated area.
10. Construction should be initiated with sufficient lead time to allow for work stoppage, legal intervention, and other delays.

The important principles involved in the operation of an electric bulk power supply system to assure a high degree of service reliability are as follows:

1. All existing switching arrangements, relaying, and protection schemes should be carefully evaluated to minimize hazards and assure system reliability.
2. Adequate communication facilities should be available at all times, both within individual systems and between systems, to assure that the data transmitted are accurate and are available during emergency conditions.
3. Adequate spinning capacity, properly distributed, should be maintained among generating units throughout the coordinated area.
4. Adequate local emergency power sources should be provided to permit safe shut-down and restarting of generating equipment in an emergency, and to maintain power supply to essential communication services, and to continue the operation of control and dispatch centers during emergency periods.
5. Automatic load shedding should be available as a means of averting widespread outages in the event of a combination of extremely improbable contingencies.
6. Continual training of all operating personnel should be practiced together with adequate written instructions, particularly for meeting emergencies.

7. Adequate and up-to-date operating instructions should be available, coordinated where necessary on a inter-system basis.
8. Sources of operating energy for all key circuit breakers in the form of compressed air or auxilitary electric power should be maintained. Such an auxiliary source of energy should be considered as part of the facilities required to restore the system after a shutdown.
9. Instrumentation that can adequately present normal system conditions with scales suitable for recording conditions which exist during major disturbances should be provided at all strategic points of operation and control. Telemetered indication of tie line power flows between areas most likely to become separated should also be provided.

Reliability of planning, design, and operation is promoted throughout the NERAC area through both the pools and the coordinating organizations.

The pools in the region are listed below and their organizational relationship are shown in Appendix D:

New England Power Pool (NEPOOL).
New York Power Pool (NYPP).
Pennsylvania-New Jersey-Maryland Interconnection (PJM).

The coordinating organizations, shown in Appendix D are:

Northeast Power Coordinating Council (NPCC).
Mid-Atlantic Area Coordination Agreement (MAAC).

The pools are concerned with the most economical planning and operations feasible after giving primary consideration to intra-pool, intraregional, and interregional reliability, while the Northeast Power Coordinating Council and the Mid-Atlantic Area Coordination Agreement groups' major thrust is in the direction of testing long range plans for bulk system security and reliability.

Standing committees and various task forces have been organized by NPCC and MAAC to establish and implement procedures for testing the effect of proposed generation and transmission facilities on the reliability of the interconnected systems. Since these organizations have been in existence for a relatively short period of time, it has not been possible for member systems to fully implement all of the important principles involved in planning, design and operation of the regional bulk power supply system previously enumerated. It is anticipated that by the early 1970's all of these principles will have been implemented fully. In the meantime specific actions which have been taken to improve the reliability of the northeast bulk power supply system include:

1. The application by 1969 of automatic load shedding equipment throughout the Northeast region.
2. Installation of improved metering and instrumentation and communication systems.
3. Provision of emergency power sources to maintain essential communications, control center services, and safe shut-down of generating equipment, and to permit rapid restoration procedures.
4. Improvement in emergency operating procedures.
5. Installation of or provision for advanced system control computers by each of three pools.
6. In addition to changes such as those enumerated above, all of the major systems of the Region participate in comprehensive joint studies which examine the stability of the networks under contingency conditions believed to impose the worst stresses to be expected in patterns of future operation, and plans are being developed to minimize the spread of any interruptions that may result.

As loads continue to grow and large generating units become more prevalent, additional transmission capability (intra- and inter-regional) will be required. Within the region, it is anticipated that the tie-lines between the New York area and the PJM area will have a power transfer capability of 2,500 Mw by 1980 and 6,000 Mw by 1990. Tie-lines betwen the New York area and the New England area are expected to have a power transfer capability of 2,000 Mw by 1980 and 5,000 Mw by 1990. In addition to these intraregional transfer capabilities, New York has major ties and a close operating relationship with Ontario Hydro in Canada. Likewise, PJM is strongly-linked with the East Central and Southeast Regions at 500 Kv.

Pools

New England Power Pool (NEPOOL)

The electric utilities of New England have a long history of coordination of operations stretching

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back to the early 1920's when the Montaup Electric Company and the Connecticut Valley Power Exchange were established. This tradition of cooperation has continued to the present with such organizations as the Connecticut Valley Electric Exchange (CONVEX) and such cooperative ventures as the series of "Yankee" atomic plants.

These cooperative ventures encouraged staggered construction of larger generating units for the benefit of electric utilities throughout New England. Numerous bilateral agreements provided for the sale of excess capacity from new units (unit sales), extensive exchanges of economy energy and the use of intervening transmission facilities. All of these activities have served to accelerate the degree and scope of coordinated planning and operation.

As additional coordination experience was gained, it became clear that an area approach to joint planning and operation was needed to develop a reliable and efficient bulk power supply system, wherein the benefits and responsibilities would be equitably apportioned. This led to the recent development of the Draft Agreement for a proposed New England Power Pool (NEPOOL). The proposal is sponsored by the nine largest electric companies in New England: Boston Edison Company, Central Maine Power Company, Central Vermont Public Service Corporation, Eastern Utilities Associates, New England Electric System, New England Gas & Electric Association, Northeast Utilities, Public Service Company of New Hampshire, and United Illuminating Company. The sponsors of the NEPOOL Agreement invited all the New England utilities, both public and private, to a meeting where the provisions of the Draft agreement were aired.

The proposed New England Power Pool Agreement makes no attempt to impose restrictions on companies or agencies who are not planning to participate in the proposed Agreement. The non-participants will not be required to maintain reserve capacities that may be called for in the Agreement. Any reserve carried by these companies or agencies will be agreed upon by direct negotiations with their interconnecting company.

The proposed agreement involves a number of pooling concepts. The objectives of NEPOOL are:

1. To attain for New England maximum practicable economy consistent with proper standards of reliability in the generation and transmission of bulk power through joint planning, central dispatching, and coordinated operation and maintenance of generation and transmission facilities.
2. To provide for equitable sharing of the resulting benefits and costs.
3. To provide a means for more effective coordination with other power pools.

An Interim Planning Committee has been activated as a first step toward an ultimate NEPOOL Planning Committee. This planning committee will be composed of representation from each of the larger utilities, one individual to represent all of the qualifying smaller investor-owned utilities, and one individual to represent all of the qualifying smaller government or cooperatively owned utilities. NEPOOL planning of bulk power supply for the region is expected to require a full-time staff of NEPOOL planners operating in continuous liaison with planning engineers of pool participants.

NEPOOL Operations

In order to implement the joint dispatch phase of NEPOOL, a skeleton staff was appointed on July 1, 1967 to set up a New England Power Exchange (NEPEX). This center is expected to be fully operational in early 1970. It will be a computerized dispatch center directing the minute-by-minute operation of the bulk transmission and generation system of New England. Generating capability for which NEPEX will be responsible when operation begins will be some 13,000,000 kw.

NEPEX, to be located at West Springfield, Massachusetts will direct operations through four computerized satellite centers:

Southington, Connecticut (CONVEX—Connecticut Valley Electric Exchange)
Westboro, Massachusetts (EMVEC—Eastern Massachusetts-Vermont Energy Control)
Manchester, New Hampshire
Augusta, Maine

The Master-Satellite system provides reliability in that loss of the master will not render the system inoperative.

The computer control system for which an order was placed on April 1, 1968 will be programmed to perform the following functions for all New England:

1. Load Frequency Control
2. Economic Dispatch
3. System Monitoring and Alarming
4. Logging and Reporting
5. Operator Information

6. Input Review (sequence of events output associated with system disturbances)
7. Load Flow
8. Maintenance Scheduling
9. Interchange Billing
10. Predictive Load Flow
11. Optimized Daily Forecast

The latter two functions are developmental in nature. The predictive load flow program will be activated automatically by contingencies and will alarm the operator of potentially dangerous situations associated with the next subsequent contingency or contingencies. The optimized forecast will coordinate four different river systems with pumped storage, nuclear thermal, and conventional thermal generation into unit commitment schedules for maximum economy of all generation sources in New England.

A comprehensive communications system to provide three reliable forms of communications between the master and the satellites is being developed. In addition, equipment has been ordered for a data link to transmit control, transmission system, and computer update information and a backup telemetering system is being evaluated.

Continuous coordination is being maintained in the development of NEPEX with the New York Power Pool control dispatch organization. Communization, telemetering, computer control and operating procedures will continue to be coordinated to assure compatibility on a regional basis.

NEW YORK POWER POOL (NYPP)

In New York State early bilateral agreements were expanded into pool operations as the capacity of interconnections increased. About thirty-five years ago Consolidated Edison, relying solely upon thermal generation, began interchange of emergency and economy energy with the predecessor company of the present Niagara Mohawk Power Corporation which had developed a substantial amount of hydroelectric capability. These arrangements were subsequently extended to include other companies. By 1961, the four companies serving southeast New York were also operating under a pool arrangement. These developments eventually led to the formation of the New York Power Pool, which was activated formally on September 1, 1966. The Power Authority of the State of New York, a State government agency, became a member of the pool October 11, 1967.

At present, seven large investor-owned systems and the Power Authority of the State of New York (PASNY) make up the membership of the New York Power Pool. These eight pool members provided 99.5% of the electric energy generated in the state in 1967. The investor-owned members of the pool supply the bulk of the demand and energy requirements of the five small investor-owned systems, one federal, and eleven municipal systems in the state. The Power Authority sells its power in wholesale amounts to 3 upstate members of the Pool, 41 municipal and cooperatively-owned electric systems in New York State, 1 cooperative in Pennsylvania, 3 industrial plants in Massena; Plattsburgh Air Force Base, and the State of Vermont—a total of 50 wholesale customers. Approximately one-half of the St. Lawrence power is sold directly to industries located adjacent to the St. Lawrence Project and one-third of the Niagara power is sold to two upstate Pool members for the express purpose of supplying industries in the Niagara Frontier area. The generating and transmission facilities of PASNY are closely integrated with those of the three upstate companies on a day-to-day basis.

In May, 1968, the New York State legislature passed a law which permits PASNY to construct and operate pumped storage developments and nuclear plants in its service area. PASNY is authorized to enter into contractual arrangements with utility companies with respect to (a) construction and operation of pumped storage facilities and supply of all or part of the necessary pumping energy by the utilities and their purchase of all or part of the output, (b) construction, ownership and/or operation of base-load nuclear generating facilities and disposition of the output, and (c) construction, ownership, operation and/or use of transmission facilities.

Although PASNY supplies power to only three members of the Pool, benefits of its peaking capacity are passed on to all of the State's utilities through the coordinated operations of the Pool.

The New York Power Pool agreement formalized and extended the coordination of planning and operation which had been carried on for many years by seven major utility companies of the state. The agreement replaced two smaller power pools and certain interchange contracts between individual utility companies.

As a member, PASNY does not participate in the commercial aspects of the NYPP operations.

However, PASNY does participate in the reliability and planning functions of the Pool. These functions include: Generation coordination, transmission line outage scheduling, participation in the cost of the master control center now under construction, and coordination of new generation sites and transmission facilities.

All municipal systems having generating resources of their own, schedule and operate their generating facilities in a manner that will limit their demand requirements from others to a minimum.

None of the five cooperatives and only a few of the municipal systems have generating facilities of their own. The City of Jamestown's 58 Mw steam-electric generating plant is the largest municipal generating facility in the state. Jamestown's reserve capacity requirements are normally supplied internally; however, the city does buy supplemental power from Niagara Mohawk whenever necessary.

The second municipal generating facility in size is the 27 Mw diesel plant of Rockville Centre. The contract between the Village of Rockville Centre and Long Island Lighting Company is primarily an emergency interchange agreement, since the interconnection is normally open. The contract also provides for an obligation for Rockville Centre to maintain an installed reserve capacity equal to fourteen percent of the highest experienced peak load in the preceding twelve-month period.

The third largest municipal generating facility is the 13 Mw diesel plant of the Village of Freeport. The power contract between the Village of Freeport and Long Island Lighting Company has included in its terms an obligation of Freeport to maintain installed reserve capacity of fourteen percent of its forthcoming estimated Summer and Winter peak load. This is the same obligation, in percent of peak load, assigned to Long Island Lighting Company by the New York Power Pool. The Village of Freeport thereby covers its proportionate share of installed reserve that otherwise would become an obligation of Long Island Lighting Company under the New York Pool Agreement.

The purpose of the New York Power Pool is to coordinate the development and operation of the production and transmission facilities of its members to obtain optimum reliability and efficiency of operation of their interconnected systems.

The Pool functions through a committee structure consisting of a Managing Committee, a Planning Committee, and a Operating Committee. The Managing Committee administers the Pool agreement.

The Planning Committee coordinates the planning of additional generating capacity and the interconnecting transmission facilities and reports upon future load requirements. The committee also makes system studies and sets system design objectives.

The Operating Committee establishes rules and procedures to coordinate the operation of the pool, formulates uniform standards and procedures for the determination of costs, establishes maintenance schedules, and determines reserve requirements and load relief. The committee also administers pool billing and central dispatch and computer application.

The pool has already adopted uniform procedures for action in a major emergency including the installation of automatic load reduction equipment to operate under defined objectives to be used by its members in the further development of the State's interconnected power system.

NYPP Operations

The Pool has recently announced plans for the installation of an energy-control center near Albany which will direct the electric power generation and transmission throughout New York State. The coordination of the operating of the State's presently installed capacity is provided by two dispatching centers whose functions are more limited than those to be assigned to the new control center scheduled for operation in June 1969.

At the center, a state-wide picture of electric generation, customer demand, and reserve capacity will be maintained continuously so that in an emergency additional amounts of power can be routed immediately to the area where it is needed. The electric energy requirements of the Pool members will be dispatched on an economy basis. The total cost of the center and the high speed communication links between it and the Pool members will be over $3,000,000.

Communication circuits will link the center with the power dispatching headquarters of each member of the Pool and with neighboring pools in Pennsylvania-New Jersey-Maryland, New England, and Ontario, Canada. Status reports on power output, customer requirements and other data will be made continuously by each company to the center over the high speed communications circuits. A completely computerized arrangement will permit

the control center to supervise continuously the loading of generation and transmission systems, insure reliability of service, and meet the normal and emergency needs of all customers most efficiently.

The Power Control Center will have a continuing responsibility for scheduling sufficient generating capability to supply reliably and economically the Pool loads including the Pool spinning reserve requirements and including contractual obligations to others. The Center will continuously monitor the operating parameters of the Pool and take such action as is necessary, will keep informed of load and capacity conditions in neighboring systems or pools, and will advise member companies and neighbors of unusual conditions within or without the Pool. Pool personnel will supervise transmission voltages throughout the Pool and direct such action as may be necessary to maintain desired voltage levels.

The center will administer the maintenance schedule for generating equipment, coordinate deviations therefrom, and will coordinate requests for maintenance outages of transmission facilities, recognizing their effect on overall system reliability. It will also coordinate operations during and following system disturbances affecting the Pool.

The on-line functions of the Power Control Center computer which is to be a part of the installed equipment in addition to providing the economic dispatch aspects, will include, as appropriate and obtainable with the most modern sophisticated computer designs, necessary checks and data provisions for system security. Among the detail items under consideration are:

- Load and stability investigations;
- Status logging and alarming of unusual loading conditions;
- Spinning reserve checks;
- Control of generating and voltage regulating equipment.

In addition to billing, scheduling energy and capacity transactions among the Pool members, optimizing the use of pumped storage generation, and evaluating interchange transactions with neighboring pools, the off-line functions will include unit commitment schedules, investigation of generator and transmission line planned outages, short-term load forecasting, and contingency studies relating to unusual system conditions.

The New York Power Pool is currently negotiating an agreement with PJM setting forth their respective rights and obligations with respect to the coordinated development and operation of their electric capacity and of energy flow between the two groups in order to obtain improvement in reliability of service to the public and reduction in cost. This agreement will supersede an existing agreement between the PJM Interconnection, Niagara Mohawk and New York State Electric and Gas.

Under the New York Pool arrangement, each member continues to be fully responsible for maintaining adequate electric generating capacity and transmission facilities within its own service area.

However, the Pool operation will enable the companies to mutually determine the best location, size, timing, and required transmission for new generating units. Fewer sites should be required and the companies will be able to build larger and more efficient generating units, thus reducing capital costs with the attendant savings to the electric customers in the state.

PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION (PJM)

The Pennsylvania-New Jersey-Maryland Interconnection is the outgrowth of a three-party agreement made in 1927. It is a formal power pool including a total of twelve operating companies. The bulk power system of each company is planned, developed, and operated as an integral part of PJM. Eight of the companies are separate corporations operating under their respective managements. Four of the companies are operating subsidiaries of one holding company. As in the case of the original three-party interconnection, PJM is operated under a one-system concept as a single control area with minute-to-minute economic dispatch of generation and with essentially free-flowing ties.

PJM functions under a written agreement that sets forth the rights and obligations of the participants and establishes the basic organization and central operating office. Nine of the companies are signatories to this agreement. Three companies are included in the power pool through separate agreements with two of the signatories to the main agreement.

The twelve operating companies are combined into the six member systems as follows:

Public Service Electric and Gas Company [3]
Philadelphia Electric Company Group
  Philadelphia Electric Company [3]
  Atlantic City Electric Company

[3] Signatories to the PJM Agreement.

Delmarva Power & Light Company
Pennsylvania Power & Light Company Group
Pennsylvania Power & Light Company [3]
UGI Corporation
Baltimore Gas and Electric Company [3]
General Public Utilities System
Jersey Central Power & Light Company [3]
Metropolitan Edison Company [3]
New Jersey Power & Light Company [3]
Pennsylvania Electric Company [3]
Potomac Electric Power Company [3]

The three operating companies which are not signatories to the main agreement are represented indirectly on the PJM Management Committee by virtue of the separate agreements between Atlantic City Electric Company and Philadelphia Electric Company, between Delmarva Power & Light Company and Philadelphia Electric Company, and between UGI Corporation and Pennsylvania Power & Light Company. On all other PJM committees and sub-committees they are either represented indirectly in a similar manner or—as in many cases—directly with their own personnel.

PJM serves a population of approximately 20 million in an area of 48,000 square miles. This covers three-quarters of Pennsylvania, almost all of New Jersey, more than half of Maryland, all of Delaware and the District of Columbia, and a small part of Virginia. PJM's 1967 summer peak load was 18,355 megawatts.

More than 99 percent of the generating capacity in FPC Power Supply Areas 5 and 6 is represented by the six member systems of PJM, their subsidiaries, and their associates. The remaining fraction of 1 percent of capacity is contributed by 13 other systems, the largest of which is Vineland municipal with less than 0.3 percent of the total. All of the other 12 systems are smaller than several of the largest industrial customers in the area with self-generation. Because these systems are so small, they have no substantive effect on area reliability, capacity planning, or operation. From the pool's viewpoint, there is no engineering or financial benefit through inclusion of these very small systems in the power pool, since their scale of operations does not contribute any reduction in overall cost to the area which is not already available within PJM.

Most of these small systems are customers, for at least part of their load, of PJM companies. To the extent they are such customers, they realize—as do all industrial, commercial, and residential customers—the benefits resulting from coordinated planning and operation, without having to participate directly in the functioning of the pool. As customers they have no reserve capacity obligation to the PJM companies serving them.

PJM has an extensive and active organization which deals continuously with matters of policy, planning and engineering, and operations. Over the years the working contact of personnel with each other, with system requirements, and with PJM objectives has lead to very effective cooperation, accomplished through committee activity. The following briefly outlines the various committees and their functions:

The Management Committee is comprised of one representative from each of the six member systems. This committee is charged with the overall direction of PJM. Three standing committees report directly to the Management Committee. These are the Planning and Engineering, Maintenance, and Operating Committees, which are described below.

The Planning and Engineering Committee is comprised of representatives of all systems. This committee is responsible for determining PJM requirements for installed generating capacity and major transmission and conducts such PJM and regional coordinated planning studies as may be required. The chairman, appointed by the Management Committee, serves for a two-year term. The associated subcommittees and their activities are given below:

1. The Program Development Subcommittee develops and maintains computer programs for the other subcommittees.
2. The Relay Subcommittee has full responsibility for reviewing and updating PJM relay protection criteria and practices for interconnection ties and associated transmission circuits. It will issue periodic reports of relay settings on lines affecting the reliability of PJM operation. The Subcommittee is also responsible for reviewing relay testing and has established a uniform PJM program.
3. The Power Plant Design Subcommittee estimates future forced and schedule outage rates for existing and proposed generating units. It also prepares cost estimates for PJM planning studies on a consistent basis.
4. The Transmission and Substation Design Subcommittees develops methods for estab-

[3] Signatories to the PJM Agreement.

lishing the maximum safe power-carrying capability of important transmission lines and equipment and prepares cost estimates for PJM planning studies on a consistent basis.

5. The Communications and Control Subcommittee reviews future communication facilities and the automatic dispatch and data transmission systems and makes recommendations on required additions and changes.
6. The Capacity and Transmission Planning Subcommittee makes coordinated planning studies of PJM reserve requirements generating capacity additions, major transmission additions and interconnections with power systems outside of PJM.

Coordinated planning studies are conducted by the Capacity and Transmission Planning Subcommittee. Several of the other subcommittees provide data for the coordinated planning studies. The use of these subcommittees to provide the data for the studies assures that all PJM data are on a consistent basis. Coordinated planning studies are made of PJM reserve requirements, generating capacity additions, major transmission additions and interconnections with power systems outside of PJM.

A PJM 10-year load and capacity forecast is issued every year, based upon the forecasts of the individual systems. The report contains PJM peak load forecasts, installed capacity reserves and calculated PJM reliability. The PJM reliability is based upon the scheduled capacity additions as projected and is developed from detailed studies which include representation of the generating units and load of PJM and the adjacent systems to which PJM is interconnected and which recognizes the interconnection transfer capability between PJM and the adjacent systems.

Coordinated studies are made periodically of PJM long range capacity requirements. The purpose of these studies is to develop general guides for the capacity expansion of PJM on a coordinated basis. These guidelines provide the preferred types, sizes, sequence, and general location for PJM capacity additions.

The Keystone Project evolved from the 1961 plan and is an example of how PJM members have been coordinating their plans on a voluntary basis. The Keystone mine-mouth generating station, near Indiana, Pennsylvania has a capacity of 1800 megawatts. It is owned by seven companies as tenants in common and is operated by Pennsylvania Electric Company as an agent for the owners. The associated transmission system consists of six transmission substations and some 600 miles of 500 Kv line connecting Keystone with load centers in central and eastern Pennsylvania and in New Jersey and Maryland and with adjacent power pools. Carrying charges on transmission facilities are shared partly in proportion to generating station ownership and partly in proportion to system load.

Transmission plans that are developed by an individual PJM member or by two or more members through joint studies are also coordinated on a PJM basis. The purpose of the PJM studies is to confirm that the projected plans developed by one or more members on a local basis do not adversely affect PJM as a whole. Planning criteria for normal and maximum credible contingencies were adopted in 1966. PJM planning criteria are being revised to meet the requirements of the MAAC planning criteria.

The Maintenance Committee is comprised of representatives of all systems. The chairman, appointed by the Management Committee, serves for a two-year term. This Committee is responsible for coordinating the major generating equipment outages for maintenance. A generating capacity maintenance schedule is prepared quarterly for the ensuing 12 months. As the year progresses, revised schedules are prepared monthly for the ensuing three months. Among the factors considered in the preparation of these schedules are planned installed capacity, firm capacity purchases and sales, forecast loads, reserves required to meet service reliability criteria, transmission and other limitations on expected capacity availability.

The Operating Committee is comprised of the Manager of the Interconnection Office who serves as a permanent chairman without vote, and of representatives of all systems. This committee directly administers the operating and accounting functions of PJM. The associated subcommittees are as follows:

1. The System Operations Subcommittee reviews those operating practices and procedures which could affect the reliability of the bulk electric supply system of PJM as a whole and makes recommendation with respect thereto.
2. The Reserve Requirement Subcommittee is responsible for the development of the operating reserve requirement of PJM. For

reliable service, sufficient capacity must be scheduled and be available to meet load requirements plus the operating reserve rerequirement.

3. The Communications Subcommittee studies the existing communication channels required for the reliable and economic operation of PJM and recommends modifications as needed.
4. The Accounting Subcommittee reviews the accounting for PJM's internal transactions and transactions with adjacent systems and recommends revised and improved accounting practices and procedures.
5. The Computer Coordination Subcommittee is responsible for making operational the digital computer and associated data transmission system being installed by PJM.

PJM Operations

A central operating headquarters, the PJM Interconnection Office, was established in 1929. It is through this office that the coordinated operation of PJM is attained.

The major responsibility of the Office is to conduct the operation of PJM to achieve maximum over-all reliability and economy of service recognizing individual system load and operating requirements, contractual obligations, and other pertinent factors. The Office is also responsible for coordinating the accounting for capacity and energy transactions.

As the result of the automatic economic dispatch of generation, energy is not scheduled in predetermined amounts or origins, but essentially flows freely over all PJM transmission facilities. The net of an individual system's hourly integrated tie-line flows results in the total energy delivered to the pool or received from the pool by that system.

Operating as a single control area, PJM has a total of 17 interarea transmission tie-lines to other pools in its automatic control scheme. The total generation of all PJM systems is regulated to match the total PJM load requirement, taking into account energy transactions with adjacent systems, frequency bias, and time error bias. Area requirement and incremental energy cost signals are transmitted from automatic load control equipment in the Interconnection office through the individual system's load control equipment to specific generating units for regulation and economic dispatch. It is through this arrangement that PJM meets its regulating obligation.

A most outstanding new development in PJM coordinated operations is the advent of the PJM computer. By the early 1960's PJM was aware of the growing complexities associated with the operation of such facilities as 1,000-megawatt generating units, a 500-kilovolt transmission system, additional and stronger interarea ties, pumped storage units and numerous small peaking units. It became apparent that the use of computers was becoming a necessity. Consequently, a detailed study was undertaken in 1964. The study culminated in the ordering of a large scale digital computer in January, 1965, an IBM System/360 Model 50 for installation in the PJM central dispatch center and subsequently in the ordering of its associated data transmission system. This computer system is now operational for some functions and the scope will be progressively enlarged.

The computer system will be used to improve the reliability and operating economy of the Interconnection through specific application areas. The initial areas are:

1. Selecting of specific generating units to meet the minute-to-minute load demands.
2. Controlling generation to maintain power flow over transmission ties to other pools within acceptable limits and to regulate frequency.
3. Monitoring power flows on major PJM transmission lines and interconnections with adjacent pools. If power flows exceed established limits or would exceed limits after loss of major facilities, the computer will describe the situation and indicate corrective measures to be taken.
4. Simulating transmission maintenance outages to determine effect on system of proposed removal of line from service.
5. Checking the PJM frequencies at selected locations as well as the inter-pool tie flows and issuing messages to the Interconnection Dispatcher describing the abnormal conditions and, by pre-planning, indicating possible corrective actions.
6. Developing the PJM costs needed to establish hourly interchange schedules between PJM and each of the neighboring pools.
7. Optimizing generation assignments throughout PJM on the basis of incremental cost

of delivered power including transmission losses.

Another step PJM has taken to increase reliability is the establishment of a remotely located emergency dispatch center which will serve as a back-up to the central dispatch center if it becomes inoperable for any reason. Other steps to increase reliability are in progress. PJM members are installing automatic load-shedding relays on 30 percent of their load. If necessary, the under-frequency relays will function automatically to drop first ten percent; then another ten percent if frequency continues to decay; and finally, a third ten percent. Service restoration to the customers affected by the relays will be much quicker than if the entire area collapsed.

Further PJM reliability measures are: Providing for a duplicate System/360 Model 50 computer as a back-up to the operational computer and to provide computer capacity for addition applications; and construction of a new PJM dispatch center with ultra-modern dispatching facilities; including the two computers and associated data transmission terminals.

Pool to Pool Agreements

In 1965, PJM entered into separate agreements with adjacent systems—Allegheny Power System, Cleveland Electric Illuminating Company, and Virginia Electric and Power Company—providing for parallel operation, for cooperation with regard to matters affecting the development of the systems of the parties and for emergency and economy interchange. Under each agreement an Operating Committee was established to administer the operating and accounting matters relating to the agreements. An Advisory Planning Committee, established under each agreement, studies and reports on joint development matters, based on an exchange of information regarding plans for modification, expansion, and development of each system's generation and transmission facilities. These studies are particularly directed to the promotion of bulk power reliability on a broad regional basis. The joint meetings lead to better interarea coordination.

An agreement with similar provisions presently is being negotiated between PJM and the electric utility systems operating in the State of New York. This agreement will supersede the present agreement with two of the companies in upstate New York, covered previously, under which power is interchanged between PJM and the New York Power Pool over six major interconnecting lines.

At a meeting with Allegheny Power System representatives in December, 1965, PJM was invited to join in an informal study group already established by Allegheny Power System, American Electric Power System, and Virginia Electric Power Company to review the operation of the 500 kilovolt system. Additional assignments were given to this group, a chairman was designated, and valuable reports were prepared on such topics as the 1967 summer capacity transfer limits between PJM and the western systems and the bulk power supply to the Chesapeake-Potomac area. Presently a regional plan for the 1972–1974 period is being developed. The study group is evaluating and coordinating the projected independently formulated plans of the participating systems based on mutually acceptable planning criteria. The study group will review future plans for the interregional area on a continuing basis.

REGIONAL OPERATING COORDINATION

It is fully recognized that as the New England and New York central dispatch centers are established, regional coordination with PJM and Ontario-Hydro will be strengthened. The Northeast Power Coordinating Council, recognizing the need for close coordination between pools, has created a Task Force on Inter-Pool Coordination. The Task Force is made up of representatives from the New York Power Pool, New England Power Exchange and Ontario-Hydro. The Task Force chaiman will invite to meetings representatives from the satellites associated with the three central control centers and representatives from neighboring or other pools. This will provide a forum aimed at furthering efficient inter-pool operations and strengthening the reliability of the Northeast Interconnected System.

As full or partial operation of the New York and New England centers come into being, definite coordination procedures for day-to-day operations will be developed. The operating functions will be administered by three dispatch centers: the New York Power Pool center now being built, the New England Power Exchange center soon to be constructed, and the existing Ontario-Hydro center. In addition to individual functions each center will participate in the overall coordination of security operations within the entire Northeast Power Coordinating Council area. Any consideration of a single security center will be deferred until after

the proposed NYPP and NEPEX centers have become operational.

The New York and New England operating organizations are already discussing computer-to-computer information update systems. These discussions contemplate mutually dependent telemetered data such as significant generation and tie line loading which might affect either pool center. This type of automatic information interchange together with a supporting teletype system should provide each dispatch center with minute-to-minute awareness of the other's problems as well as an indication of potentially dangerous situations which could occur during the next twenty-four hours or longer.

Canada United States Eastern Interconnection (CANUSE) cooperates with, and assists the Northeast Power Coordinating Council in matters concerning the operation of the interconnected system. At the request of NPCC, CANUSE develops operating instructions covering changes in the interconnected system resulting from Council action. The Council conducts computer studies of tie-line loadings and makes other information available for the guidance of the CANUSE membership.

A close liaison is maintained between NPCC and CANUSE to avoid unnecessary duplication of effort.

CANUSE has two representatives on the North American Power Systems Interconnection Committee (NAPSIC) so that the deliberations of that organization are available to the Council.

The PJM Interconnection has telephone communication circuits with all its neighboring pools (CEI, APS, VEPCO, NYPP) to aid in coordination procedures. In addition to the voice-grade communication facilities, there are two closed-loop teletype systems. One system links the dispatching center of PJM in Philadelphia with Syracuse (for NYPP), Southington, Connecticut (for New England), and Toronto (for Ontario Hydro). The other connects PJM with dispatching centers of pools to the west and south. Using these facilities PJM and its neighbors keep each other informed of any situations, such as scheduled equipment outages, which may have an effect on the operation of the interconnected systems. Emergency procedures have been established so each system will give maximum reasonable assistance to adjacent systems in case of disturbances.

In addition, PJM and other pools in the region conduct regional studies from time to time to establish safe operating limits during various system conditions. In the near future the recently installed PJM dispatch computers will aid the dispatcher in pool-to-pool operations.

Regional coordination on a minute-to-minute basis, at present in its infancy, is not being overlooked in the development of the central dispatch in the Northeast.

Coordinating Organizations

NORTHEAST POWER COORDINATING COUNCIL (NPCC)

In December 1965 the large electric systems in New England, New York, and Ontario proposed that a permanent organization be established to promote reliability and to expand coordination of planning and operating of the interconnected electric systems of the principal companies and agencies supplying electricity within the area.

In January 1966, agreement was reached by 22 electric utility company systems setting up the Northeast Power Coordinating Council. These systems included the Power Authority of the State of New York and the Hydro-Electric Power Commission of Ontario. Council members represent about 98 percent of the electric generating capacity in the area in which they serve. The aggregate installed generating capacity of the member systems is now in excess of 35 million kilowatts.

The Council is essentially an extension of the somewhat less formal relationship that had been developed between these systems over a period of years.

The Council's purpose is to promote maximum reliability and efficiency of electric service in the interconnected systems by extending the coordination of their system planning and operating procedures.

The main thrust of the Council's activities is toward service reliability. The Council assembles system planning and operation information furnished by the members and by means of sophisticated computer programming, tests the performance compatibility of the overall interconnected systems.

Since the Council's organization in 1966, Burlington Electric Light Department has joined as a new member and The Connecticut Light and Power Company, The Hartford Electric Light Company, Holyoke Water Power Company, and Western Massachusetts Electric Company have affiliated into Northeast Utilities, leaving the present membership at 20 systems.

The Council's principal functions are to receive and act on recommendations of its standing committees, to provide policy direction to its standing committees, to approve an annual administrative budget and to assess the membership dues in support of the budget. The budget for the current year is over $325,000, which includes an item of over $100,000 for computer studies.

The work of the Council is carried out under the direction of an Executive Committee consisting of nine members and a Chairman. The Council also has a full time Administrative Manager and secretarial staff.

Representation on the Executive Committee is on a regional basis with two representatives from the Upstate New York investor owned companies, two representatives from the Southeast New York investor owned companies, three representatives from New England, one representative from the Power Authority of the State of New York, and one representative from Hydro-Electric Power Commission of Ontario.

In addition to the Executive Committee, the Council has these standing Committees:

- System Design Coordinating Committee
- Operating Procedure Coordinating Committee
- Public Relations Committee

The standing committees' representation is also on a regional basis.

The System Design Coordinating Committee from time to time recommends criteria for elements of design which affect the operating reliability of the interconnected systems, and the Operating Procedure Coordinating Committee recommends standards for elements of operating procedure which affect the operating reliability of the interconnected systems.

The member systems report to the Council promptly any significant alterations or changes proposed for their systems or changes in its operating procedures.

These notifications are for proposed changes whether in generation, transmission, intersystem communication, or control and protective equipment. These reports are submitted promptly and, except in cases of emergency, before commitments are made for alterations or changes in facilities or changes in operating procedures are scheduled to become active. The council promptly informs all members of such proposals and refers the proposal to the System Design Coordinating Committee and to the Operating Procedure Coordinating Committee for study and evaluation. Upon completion of such study and evaluation each member system receives a report of the findings, conclusions, and recommendations of the standing committees with respect to any determinable effect upon the interconnected systems.

A special meeting of the full membership of the Council may be called to consider further the effect of any such proposed alteration or change on the interconnected systems and to consider the feasibility of any reasonable alternatives thereto.

At present, there are six working task forces which report to the System Design and Operating Procedure Committees:

- Task Force on System Studies
- Task Force on System Protection
- Task Force on On-Line Computers
- Task Force on Load and Capacity
- Task Force on Load Reduction and Spinning Reserve
- Task Force on Inter-Pool Coordination

The Task Force on System Studies original assignment was to evaluate a series of studies made by Stone & Webster and by the Federal Power Commission Task Force. The NPCC Task Force on System Studies has since initiated a program of system studies to test the compatibility and reliability of individual system design with relation to the entire Northeast interconnected systems. To strengthen inter-regional coordination the task force is now making system studies in conjunction with PJM; and other studies with PJM and the Michigan-Indiana-Illinois-Ohio group (MIIO).

The Task Force on System Protection is not confined to the analyses or protective relaying but considers all phases of system protection. The task force to date has completed or is continuing these studies:

- Relay maintenance practices of member companies.
- Basic protection of bulk power supply system.
- A mathematical model of the behavior of large power systems.
- Methods of installing under-frequency relays, including wiring diagrams.

The Task Force on On-Line Computers is investigating the possibilities of on-line computers for achieving more reliable and more economic operations within each system and, through proper coordination, within the entire NPCC area. It is now

studying the economic and technical feasibility for using hybrid computers (combination of analog and digital computers) for on-line system operation. Investigation is now underway to determine methods by which computers in each satellite control center could converse with each other.

The Task Force on load and capacity is charged with the preparation of periodic summaries of predicted loads for the areas served by members of the Council for a period looking seven years ahead, and showing two years of past history. This report includes all existing generation and major transmission in the area served by the members of the Council, including interconnections to other systems.

The Task Force on Load Reduction and Spinning Reserve studies the pattern of spinning reserve that each member commits itself to maintain. This commitment is based on local regional requirements. However, the local regional patterns must be compatible with the entire NPCC area.

The Task Force on Inter-Pool Coordination provides active coordination of operations among the New York Power Pool, New England Power Pool, and Ontario-Hydro. Close liaison is also maintained with adjoining pools.

NPCC Reliability Criteria

An interconnected power system should be designed and operated at a level of reliability such that the loss of a major portion of the system does not result from reasonably foreseeable contingencies.

In determining this reliability, members of the Council deem it desirable to consider all combinations of contingencies occurring more frequently than once in some stipulated number of years. However, sufficient data and techniques are not available at the present time to define all possible contingencies which might occur, nor is the state of the art advanced enough to assess and rank the probability of occurrence of all improbable but possible events which may be hypothesized.

The Council, therefore, decided that the interconnected systems should be designed and operated to meet certain specified contingencies described in the document "Basic Criteria for Design and Operation of Interconnected Systems". Another document entitled "Procedure in a Major Emergency" sets forth criteria for automatic load shedding and other load relief procedures, and establishes general criteria for system restoration activities. Both of these documents are included in Appendix B.

MID-ATLANTIC AREA COORDINATION AGREEMENT (MAAC)

The Mid-Atlantic Area Coordination Agreement was formulated to provide a mechanism to augment further the planning for reliability of the bulk power system of the PJM area. The initial signatories of MAAC are the twelve operating companies already included in the coordinated operation of PJM. Prior to MAAC, the reliability function for the PJM area (including Atlantic City, Delmarva, and UGI) was accomplished by the voluntary action of the several companies through various PJM committees on an informal and noncontractual basis. Now, under MAAC the same twelve operating companies will have their plans formally reviewed and evaluated from a bulk power system reliability standpoint.

Because PJM and MAAC are made up of the same twelve operating companies, a considerable degree of interrelationship of committee personnel and assignments is to be expected. The two groups, though, do have different purposes and objectives: PJM to develop and coordinate long- and short-range plans to meet the specific needs of the area and to operate the combined systems to achieve maximum overall reliability and economy, MAAC to review and determine the effect upon the reliability of the area bulk power system of additions, modifications, or removals of generating and bulk transmission facilities planned by the individual companies within the framework of PJM long-range plans and policies.

The Agreement was executed on December 26, 1967. It has three principal features:

1. The signatories formally pledge to submit their tentative plans to the Executive Board for study by the Area Coordination Committee and review by the Board to determine whether or not developments within PJM will be in accord with MAAC planning standards.
2. A mechanism is set up for coordination of reliability activities on an interarea basis, that is between MAAC and its counterparts to the north, west, and south.
3. Other systems may become signatories if their generation and transmission systems are such that they would significantly affect the reliability of the bulk electric supply systems of the signatories.

An Executive Board and an Area Coordination Committee are established by the Agreement.

The Executive Board consists of one representative from each member company or system. The Executive Board has established and will periodically review principles, standards, and procedures relating to matters affecting the reliability of the bulk electric supply system. These standards are an evolution from those used by the PJM Planning and Engineering Committee. Revisions will probably be made as the need develops to rationalize MAAC standards with those used in the contiguous reliability coordination areas.

The Area Coordination Committee is appointed by the Executive Board. On a continuing basis, it will review reliability principles, standards, and procedures. This committee will also review and evaluate the members' plans for generation and transmission facilities and other matters relevant to the reliability of the bulk electric supply system. Recommendation will then be submitted to the Executive Board. A copy of the agreement setting forth committee procedures is included in Appendix C.

Each signatory to the MAAC Agreement will report to the Executive Board its plans for the addition, modification, or removal of generating and transmission facilities. These plans will be referred to the Area Coordination Committee for review. After receiving the recommendations of the Area Coordination Committee, the Executive Board will decide if the plans are in accord with the established planning standards and that such plans do not adversely affect area reliability. If the Board decides that the plans do not meet these requirements, it shall so inform the signatory involved and request that the proposal be modified. A detailed statement of the reliability principles and standards that have been adopted is given in Appendix C.

Interregional Coordination

A logical extension of regional coordination is interregional coordination. Since the NPCC systems are now linked to those in ECAR and CARVA only through the MAAC systems, MAAC is the obvious mechanism to coordinate the bulk power reliability of its signatories with counterpart councils to the north, west, and south. Agreements between NPCC and MAAC and between MAAC, ECAR, and CARVA are now in the formative state. In the future, when additional ties are completed across the southern boundary of Michigan, a direct relationship between NPCC and ECAR may be desirable. Also, NPCC, MAAC, ECAR, and CARVA are members of the National Electric Reliability Council.

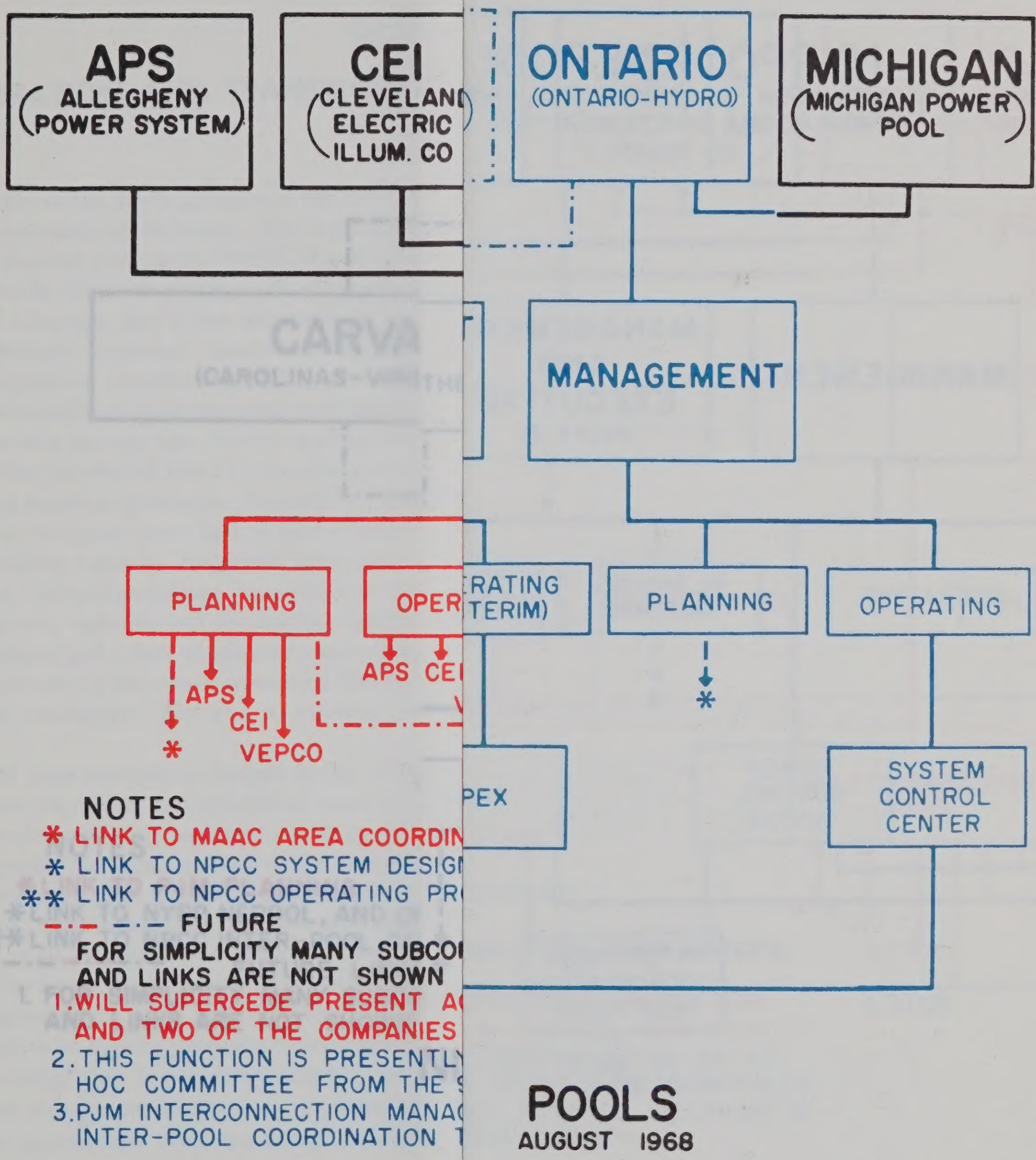

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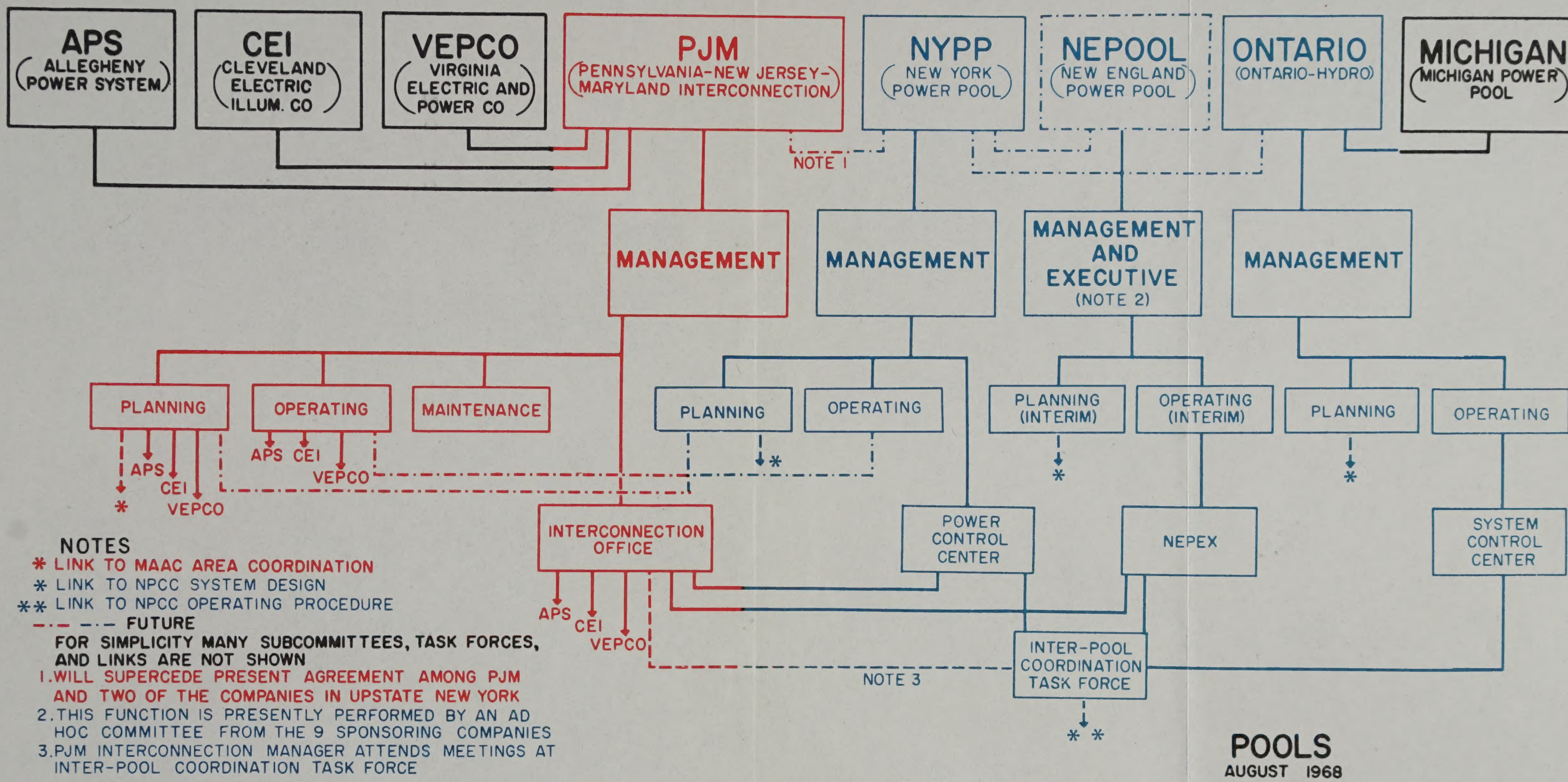
Figure 15



APS
ALLEGHENY POWER SYSTEM
CEI
CLEVELAND ELECTRIC ILLUM. CO
VEPCO
VIRGINIA ELECTRIC AND POWER CO
PJM
PENNSYLVANIA-NEW JERSEY-MARYLAND INTERCONNECTION
NYPP
NEW YORK POWER POOL
NEPOOL
NEW ENGLAND POWER POOL
ONTARIO
(ONTARIO-HYDRO)
MICHIGAN
MICHIGAN POWER POOL
NOTE 1
MANAGEMENT
MANAGEMENT
MANAGEMENT AND EXECUTIVE (NOTE 2)
MANAGEMENT
PLANNING
OPERATING
MAINTENANCE
PLANNING
OPERATING
PLANNING (INTERIM)
OPERATING (INTERIM)
PLANNING
OPERATING
APS
CEI
VEPCO
*
APS CEI
VEPCO
INTERCONNECTION OFFICE
APS
CEI
VEPCO
POWER CONTROL CENTER
NEPEX
SYSTEM CONTROL CENTER
INTER-POOL COORDINATION TASK FORCE
NOTE 3
* *
NOTES
* LINK TO MAAC AREA COORDINATION
* LINK TO NPCC SYSTEM DESIGN
** LINK TO NPCC OPERATING PROCEDURE
—·— —·— FUTURE
FOR SIMPLICITY MANY SUBCOMMITTEES, TASK FORCES, AND LINKS ARE NOT SHOWN
1. WILL SUPERCEDE PRESENT AGREEMENT AMONG PJM AND TWO OF THE COMPANIES IN UPSTATE NEW YORK
2. THIS FUNCTION IS PRESENTLY PERFORMED BY AN AD HOC COMMITTEE FROM THE 9 SPONSORING COMPANIES
3. PJM INTERCONNECTION MANAGER ATTENDS MEETINGS AT INTER-POOL COORDINATION TASK FORCE
POOLS
AUGUST 1968

Figure 15

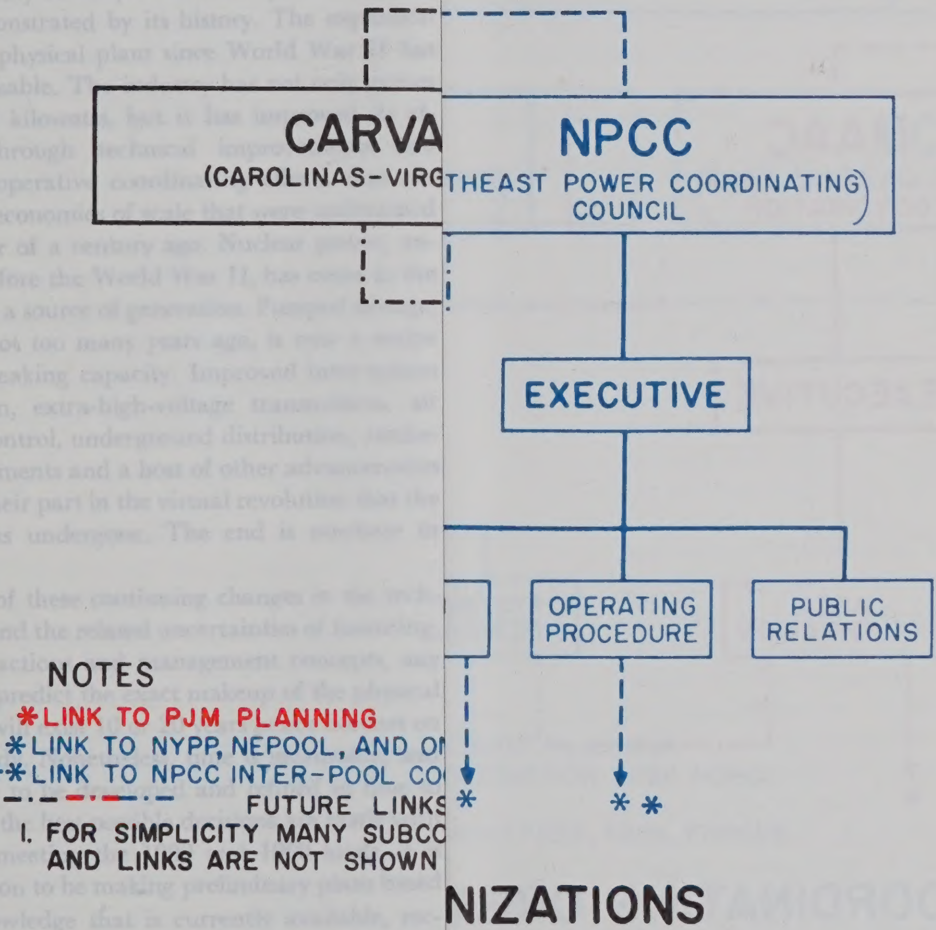


Figure 16

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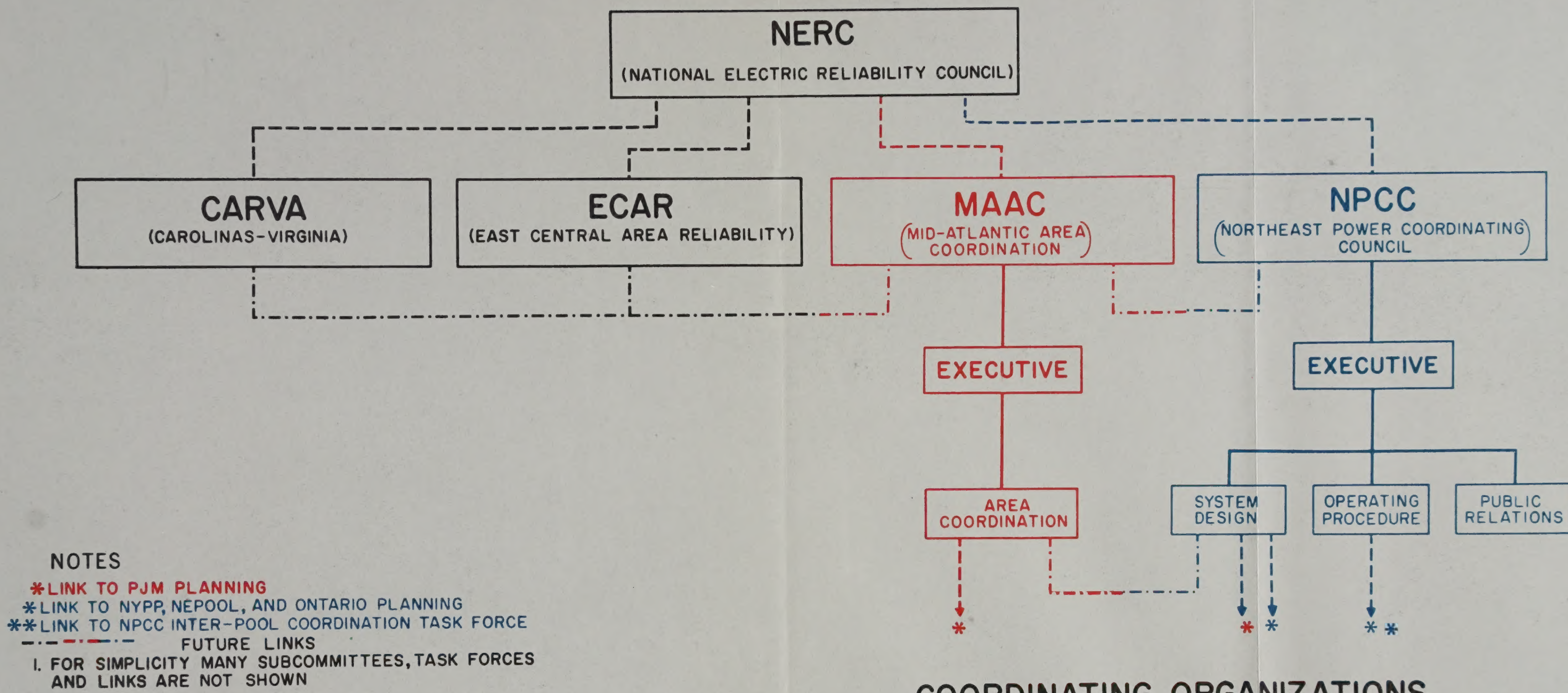

COORDINATING ORGANIZATIONS
AUGUST 1968

Figure 16

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CHAPTER IX

GENERATION AND TRANSMISSION PATTERNS FOR 1980 AND 1990

General

The viability of the power industry in the Northeast is demonstrated by its history. The expansion rate of the physical plant since World War II has been remarkable. The industry has not only grown in terms of kilowatts, but it has improved its efficiencies through technical improvements and through cooperative coordinating efforts that are permitting economies of scale that were undreamed of a quarter of a century ago. Nuclear power, unheard of before the World War II, has come to the forefront as a source of generation. Pumped storage, a novelty not too many years ago, is now a major source of peaking capacity. Improved inter-system coordination, extra-high-voltage transmission, air pollution control, underground distribution, aesthetic improvements and a host of other advancements have had their part in the virtual revolution that the industry has undergone. The end is nowhere in sight.

Because of these continuing changes in the technical field and the related uncertainties of financing, regulatory actions and management concepts, any attempt to predict the exact makeup of the physical plant that will exist 10 or 20 years hence borders on the foolhardy. Nonetheless, time is inexorable, and if plans are to be developed and refined in time to insure that the best possible decisions are made with respect to meeting the 1980 and 1990 loads, it is none too soon to be making preliminary plans based on the knowledge that is currently available, recognizing that changes are inevitable as the time for construction approaches. With this broad reservation, the committee has attempted to weight the factors, discussed in the previous chapters, that are believed to be most significant in effecting generation and transmission patterns in the next two decades, and has developed the general plans suggested by Table 18 and Figure 17.

No one—or at least no one on the Committee—will argue that these prognostications are a blueprint for future developments in the Northeast, or even that there will not be significant technological, economic, political, or social changes within the next few years that might change the basic concepts on which these estimates were made.

Basic Assumptions

Recognizing these pitfalls, the estimates have been made, based on these general assumptions:

1. General economic considerations, based on projections made of the Office of Business Economics, United States Department of Commerce.[1]
   - (*a*) National population will increase at about the median range of the OBE projections, from 195 million in 1965 to about 300 million by 1990, indicating an annual growth rate of about 1.5 percent. Population of the Northeast region will increase from about 44 million in 1965 to nearly 60 million by 1990, indicating that the Region's share of the national total will decline slightly during the period.
   - (*b*) National production will increase from a GNP level of about $617 billion in 1965 to about $1,750 billion by 1990.[2] In line with the decline in the region's share of national population, both the region's proportional contribution to gross national product and the regional share of national power consumption are expected to decrease slightly during the 1965–1990 period.
   - (*c*) Per capita personal income in the Northeast will increase from about $2,700 in 1965 to nearly $6,000 in 1990.[2]

[1] The basic material was prepared for use in the North Atlantic Regional Water Resources Study, sponsored by the Corps of Engineers, Department of the Army.

[2] Based on 1958 dollar values.

2. Social outlook
   (*a*) There will be continuing national and regional concerns with the amenities of living. Air pollution control, aesthetics, water temperature control and related items will be major influences on management decisions.
   (*b*) The continued economic growth and improved economic status of utility customers will lead to continuing, and in some cases expanding, demands for currently available and new types of household appliances and home equipment, including both air conditioning and home heating. There will be some expanded use of electrical heating and air-conditioning of public facilities and business establishments, but no major trends toward such things as street-heating or open-space temperature control.
3. Fuels
   (*a*) Needed fuels will be available at higher, but competitive prices.
   (*b*) Coal will continue to be used to the extent that its use is economically attractive.
   (*c*) Nuclear fuel will be available as needed. Breeder reactors will be developed for commercial use in the period after 1980.
   (*d*) There will be no prohibitive restrictions on fuel imports, or the movement of fuel in international waters.
4. Technology
   (*a*) There will be continuing technological improvements, but no changes in the currently accepted concepts of generation and transmission, except for the introduction of breeder reactors.
   (*b*) Underground cable will be developed for use at all anticipated voltages. Economics will permit undergrounding of most new distribution facilities, and transmission facilities in highly congested areas. Other transmission will continue to be carried on overhead systems except for limited areas of outstanding scenic or other values.
   (*c*) Direct current transmission at all anticipated voltage will be technically feasible. Its use, however, will be dictated by its overall economic advantages, and would not change the basic transmission patterns anticipated. For simplicity, the plans presented show only AC transmission, but this does not prejudice substitution of DC should it be found more advantageous.
5. Regulations
   (*a*) The increasing complexities of the problems to be considered by local, state, and Federal regulatory groups will not result in any significant extension of lead time requirements now being experienced.
   (*b*) Nuclear plant siting in relatively congested areas will be permitted.

Projections for 1980 and 1990

Table 18 shows preliminary estimates of future loads in Region I, and the probable types and amounts of generation that will be used to meet future requirements if there are no significant changes during the next two decades in technology, economic conditions, or other pertinent factors. Actually, such changes are bound to occur, and if and when they do they will alter the total power requirements and/or the relations between generation types. The figures in Table 18 are, therefore, indications of general magnitudes rather than precise predictions.

TABLE 18

Region I—Northeast Regional Advisory Committee, Estimated Future Installed Generating Capacity Requirements

	Coordinated study area						Region I	
	A		B		C			
	(Mw)	(Percent total)	(Mw)	(Percent total)	(Mw)	(Percent total)	(Mw)	(Percent total)
1970								
Conventional Hydro [1] [2]	1, 202	9. 5	3, 725	17. 0	930	3. 3	5, 857	9. 4
Pumped Storage	30	0. 2	240	1. 1	1, 160	4. 2	1, 430	2. 3
IC/GT	950	9. 5	700	3. 2	1, 630	5. 9	3, 280	5. 3
Total Fossil Steam [3]	9, 030	71. 4	14, 770	67. 4	23, 370	84. 1	47, 170	75. 6
Units 1—400 Mw	8, 520	67. 4	13, 200	60. 2	17, 080	61. 5	38, 800	62. 2
Units 401—800 Mw	510	4. 0	540	2. 5	3, 550	12. 8	4, 600	7. 4
Units 801—1200 Mw			1, 030	4. 7	2, 740	9. 8	3, 770	6. 0
Units Over 1200 Mw								
Total Nuclear Steam	1, 440	11. 4	2, 480	11. 3	690	2. 5	4, 610	7. 4
Units 1—400 Mw	190	1. 4	270	1. 2	50	0. 2	510	0. 8
Units 401—800 Mw	1, 250	9. 9	1, 140	5. 2	640	2. 3	3, 030	4. 9
Units 801—1200 Mw			1, 070	4. 9			1, 070	1. 7
Units Over 1200 Mw								
Total Capacity	12, 652	100. 0	21, 915	100. 0	27, 780	100. 0	62, 347	100. 0
Coincident Peak [4]	11, 800		17, 060		24, 120		51, 230	
Percent Margin	7. 2		28. 5		15. 2		21. 7	
Retirements	30		20		240		290	
1980								
Conventional Hydro [1] [2]	1, 202	4. 3	3, 725	10. 8	930	1. 7	5, 857	5. 0
Pumped Storage	2, 630	9. 4	3, 240	9. 4	3, 510	6. 5	9, 380	8. 1
IC/GT	3, 200	11. 4	3, 100	9. 0	2, 500	4. 6	8, 800	7. 5
Total Fossil Steam [3]	9, 778	34. 9	11, 005	31. 8	31, 100	57. 2	51, 883	44. 4
Units 1—400 Mw	8, 068	28. 8	9, 435	27. 3	15, 660	28. 8	33, 163	28. 4
Units 401—800 Mw	1, 710	6. 1	540	1. 5	4, 900	9. 0	7, 150	6. 1
Units 801—1200 Mw			1, 030	3. 0	10, 540	19. 4	11, 570	9. 9
Units Over 1200 Mw								
Total Nuclear Steam	11, 190	40. 0	13, 480	39. 0	16, 300	30. 0	40, 970	35. 0
Units 1—400 Mw	190	0. 7	270	0. 8	50	0. 1	510	0. 4
Units 401–800 Mw	6, 400	22. 9	1, 140	3. 3	640	1. 2	8, 180	7. 0
Units 801—1200 Mw	4, 600	16. 4	12, 070	34. 9	15, 610	28. 7	32, 280	27. 6
Units Over 1200 Mw								
Total Capacity	28, 000	100. 0	34, 550	100. 0	54, 340	100. 0	116, 890	100. 0
Coincident Peak [4]	22, 100		28, 470		45, 270		92, 770	
Percent Margin	26. 7		21. 4		20. 0		26. 0	
Retirements	1, 282		3, 785		1, 660		6, 727	

See footnotes at end of table.

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TABLE 18—Continued

Region I—Northeast Regional Advisory Committee, Estimated Future Installed Generating Capacity Requirements—Con.

	Coordinated study area						Region I	
	A		B		C			
	(Mw)	(Percent total)	(Mw)	(Percent total)	(Mw)	(Percent total)	(Mw)	(Percent total)
				1990				
Conventional Hydro [1], [2]	1, 202	2. 3	3, 725	6. 2	930	0. 9	5, 857	2. 7
Pumped Storage	4, 630	8. 9	6, 240	10. 4	4, 510	4. 5	15, 380	7. 2
IC/GT	4, 800	9. 2	6, 300	10. 6	5, 100	5. 0	16, 200	7. 6
Total Fossil Steam [3]	9, 278	17. 8	9, 005	15. 1	33, 230	32. 7	51, 513	24. 1
Units 1—400 Mw	6, 568	12. 6	7, 435	12. 5	13, 790	13. 6	27, 793	13. 0
Units 401—800 Mw	2, 710	5. 2	540	0. 9	4, 900	4. 8	8, 150	3. 8
Units 801—1200 Mw			1, 030	1. 7	14, 540	14. 3	15, 570	7. 3
Units Over 1200 Mw								
Total Nuclear Steam	32, 190	61. 8	34, 480	57. 7	57, 800	56. 9	124, 470	58. 4
Units 1—400 Mw	190	0. 4	270	0. 5	50		510	0. 2
Units 401—800 Mw	6, 400	12. 3	1, 140	1. 9	640	0. 6	8, 180	3. 8
Units 801—1200 Mw	4, 600	8. 8	19, 070	31. 9	15, 610	15. 4	39, 280	18. 5
Units Over 1200 Mw	21, 000	40. 3	14, 000	23. 4	41, 500	40. 9	76, 500	35. 9
Total Capacity	52, 100	100. 0	59, 750	100. 0	101, 570	100. 0	213, 420	100. 0
Coincident Peak [4]	41, 300		48, 100		80, 190		164, 640	
Percent Margin	26. 2		24. 2		26. 7		29. 6	
Retirements	2, 782		5, 785		3, 530		12, 097	

[1] It is recognized that conventional hydro capacity is subject to removal from service for various reasons, but the amount likely to be retired during the period is considered to be insignificant.

[2] No allowance has been made for any increase in conventional hydro capacity because of limited opportunities in the Northeast as discussed in Chapter III. However, it is recognized that the potential for some future developments exist, the most significant of which are the proposed Dickey-Lincoln School project on the upper St. John River and expansion of existing plants on the Kennebec and Susquehanna Rivers.

[3] Reflects retirements, all assumed in the 1–400 Mw unit range.

[4] From Table 1 Summary.

APPENDIX A

INVENTORY OF EXISTING AND POTENTIAL POWER RESOURCES

Undeveloped Conventional Hydroelectric Sites

Name of plant	River	State	Installed capacity (KW)	Average [4] annual generation (MWH)	Useable power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
		STUDY AREA A					
Harris	Kennebec	Maine	[1] 130, 000	....	16. 1	159	E–A
Wyman	do	do	[1] 70, 000	....	66. 7	145	E–A
Upper Kennebec [5]	do	do	570, 000	499, 300	Pondage	405	U
Lower Androscoggin [5]	Androscoggin	do	85, 000	300, 000	655. 0	....	R
Dickey-Lincoln School	St. John	do	[2] 830, 000	1, 154, 000	2, 900. 0	310	A
Hart Island	Connecticut	N.H., Vt.	45, 000	125, 000	Pondage	30	U
Enfield Rapids	do	Connecticut	62, 100	267, 000	9. 1	36. 5	U
		STUDY AREA B					
Hudson Falls	Hudson	New York	51, 200	215, 000	N.A.	80. 0	U
		STUDY AREA C					
Holtwood	Susquehanna	Pennsylvania	[3] 269, 200	820, 000	....	....	E–A
Safe Harbor	do	do	[3] 303, 000	1, 030, 000	68. 9	54. 0	E–A
Safe Harbor	do	do	[3] 406, 000	1, 120, 000	68. 9	54. 0	U
Marysville	do	do	180, 000	520, 000	35. 0	32. 0	U
Half Falls	do	do	160, 000	850, 000	80. 0	75. 0	U
Falls	do	do	250, 000	760, 000	1, 000. 0	150. 0	U
Clarion	Clarion	do	100, 000	240, 000	661. 0	236. 0	U
Keating	W. Br. Susq	do	260, 000	390, 000	796. 0	278. 0	U

[1] Added capacity at an existing plant.

[2] As of June 1968.

[3] Total capacity after expansions. Potentials shown are alternatives.

[4] Estimated.

[5] Aggregate of two or more projects.

NOTES.—N.A.—Data not available; E—Existing plant; A—Development or redevelopment under active consideration; U—Undeveloped, but potential site; R—Redevelopment.

Existing Conventional Hydroelectric Plants

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
			STUDY AREA A				
Central Maine Power Company:							
Harris	Kennebec	Maine	75, 000	183, 610	16. 07	159	(3)
Wyman	do	do	72, 000	317, 310	66. 7	145	(3)
Williams	do	do	13, 000	95, 787	3. 05	50	....
Weston	do	do	12, 000	83, 633	2. 55	35	....
Shawmut	do	do	4, 650	47, 556	nil	24	....
Gulf Island	Androscoggin	do	19, 200	125, 324	10. 0	59	....
Androscoggin No. 3.	do	do	3, 600	26, 600	0. 23	36	....
Deer Rips	do	do	6, 540	30, 570	0. 23	33	....
Continental	do	do	1, 776	8, 000	nil	23	....
Topsham	do	do	900	7, 404	nil	20	....
Brunswick	do	do	1, 473	11, 579	nil	15	....
Hiram	Saco	do	2, 400	22, 037	0. 8	77	....
Bonny Eagle	do	do	7, 200	44, 317	1. 1	38	....
Buxton	do	do	6, 625	29, 808	0. 18	28	....
Bar Mills	do	do	4, 000	21, 528	nil	22	....
Skelton	do	do	16, 800	105, 085	3. 6	78	....
Cataract	do	do	6, 650	44, 968	0. 7	40	....
Oakland	Messalonskee	do	2, 800	8, 670	nil	68	....
Rice Rips	do	do	1, 600	4, 776	nil	43	....
Automatic	do	do	800	2, 667	nil	22	....
Union Gas	do	do	1, 500	4, 770	nil	36	....
Fort Halifax	Sebasticook	do	1, 500	6, 449	....	22	....
Kezar Falls	Ossipee	do	350	1, 692	nil	19	....
N. Gorham	Presumpscot	do	2, 250	11, 210	....	34	....
Bangor Hydro-Electric Company:							
Medway	Penobscot	do	3, 440	27, 003	....	16	....
Stanford	do	do	3, 800	24, 050	....	21	....
Milford	do	do	6, 400	48, 351	....	20	....
Veazie	do	do	8, 400	53, 467	....	18	....
Howland	Piscataguis	do	1, 875	12, 071	....	16	....
Stillwater	Stillwater	do	1, 950	12, 587	....	18	....
Orono	do	do	2, 332	15, 050	....	25	....
Machias	Machias	do	350	1, 869	....	25	....
Ellsworth	Union	do	8, 900	31, 155	nil	60	....
Maine Public Service Company:							
Squa Pan Hydro	Squa Pan	do	1, 500	700	57. 5	30	....
Caribou Hydro	Aroostook	do	800	5, 000	....	12	....
Rumford Falls Power Company:							
Upper Station	Androscoggin	do	21, 970	158, 514	nil	97	....
Lower Station	do	do	12, 800	103, 506	nil	78. 5	....
Lewiston Muni. Lt. Plant:							
Lewiston	do	do	700	5, 000	0	N.A.	....
City of Bangor:							
Bangor	Penobscot	do	700	4, 500	0	10	....
Rangeley Power Co.:							
Eustis	Dead	do	250	800	nil	15	....
Kennebunk Light and Power Co.:	Mousam	do	150	1	nil	15	....
Madison Electric Works:							
Norridgewock	Sandy	do	500	3, 000	....	17	....
Woodsville (N.H.) Fire District:							
Woodsville	Ammonoosuc	N.H	400	1, 847	N.A.	N.A.	....

See footnotes at end of table.

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
STUDY AREA A—Continued							
Littleton (N.H.) Water and Light Dept.:							
Apthrop Station.	Ammonoosuc	N.H.	300	1, 400		21	
New England Power Company:							
Moore	Connecticut	do	140, 400	242, 000	114. 2	159	
Comerford	do	do	140, 400	281, 900	32. 3	179	
McIndoes	do	do	10, 560	43, 200	5. 0	29	
Wilder	do	N.H. and Vt.	32, 400	136, 200	13. 4	53	
Bellows Falls	do	Vermont	40, 800	220, 800	9. 6	62	
Vernon	do	N.H. and Vt.	24, 400	119, 200	18. 3	34	
Granite State	Mascoma	N.H.	1, 300	5, 000	N.A.	73	
Searsburg	Deerfield	Vermont	4, 000	23, 500	Pondage	232	
Harriman	do	do	33, 600	97, 400	116. 1	390	
Sherman	do	Mass.	7, 200	25, 400	1. 7	80	
Deerfield No. 5	do	do	15, 000	72, 100	Pondage	245	
Deerfield No. 4	do	do	4, 800	26, 000	Pondage	68	
Deerfield No. 3	do	do	4, 800	29, 000	Pondage	68	
Deerfield No. 2	do	do	4, 800	26, 300	Pondage	63	
Bozrah Light and Power Co.:							
Gilman.	Yantic	Connecticut	250	500	N.A.	29	
United Illuminating Company:							
Derby Power Sta.	Tonousatanic	do	800	[4] 1, 503. 0	[5]	18	
Holyoke Gas and Electric Department:							
No. 1	Conn.-Canal	Mass.	1, 056	3, 600		19	
No. 2	do	do	800	4, 500		19. 4	
No. 3	do	do	450	3, 100		12. 4	
No. 4	do	do	600	3, 000		18	
City of Norwich (Conn.) Dept. of Public Utilities:							
Second Street	Shetucket	Connecticut	800	6, 133	[7] 0. 240	16	
Tenth Street	do	do	1, 400	4, 319		15. 5	
Occum	do	do	800	4, 545	0. 134	13	
City of Providence:							
Gainer Dam	Pawtucket	R.I.	1, 500	1, 500	N.A.	86	
White Mountain Power Company:							
Goodrich Falls	Glen Ellis	N.H.	500	1, 500	N.A	67	
Northeast Utilities:							
Cabot	Connecticut	Mass.	51, 000	243, 459	[7] 8. 49	61. 5	
Turners Falls No. 1	do	do	4, 840	11, 969		43. 7	
Gardners Falls	Deerfield	do	3, 980	17, 973	0. 04	39	
Red Bridge	Chicopee	do	3, 600	18, 963	0. 53	49. 5	
Putts Bridge	do	do	3, 200	16, 227	0. 32	40	
Indian Orchard	do	do	4, 900	14, 901	0. 07	34	
Dwight	do	do	1, 440	9, 883	0. 07	34	
Cobble Mountain	Westfield-Little	do	33, 000	21, 578	61. 52	456	[8]
Shepang	Housatonic	Connecticut	37, 200	[6] 118, 230	5. 4	97	
Bulls Bridge	do	do	8, 400	[6] 47, 200	0. 233	107	
Stevenson	do	do	30, 500	[6] 97, 650	5. 038	74. 5	
Falls Village	do	do	9, 000	[6] 39, 409	0. 43	91. 6	
Scotland	Shetucket	do	2, 000	[6] 7, 630	0. 268	27	
Taftville	do	do	1, 780	[6] 7, 740	0. 3	25	
Tunnel	Quinebaug	do	2, 000	[6] 10, 600	0. 115	23	
Bantan	Bantam	do	320	[6] 1, 300	0. 004	62	
Robertsville	Still	do	500	[6] 1, 800	0. 037	60	

See footnotes at end of table.

Name of plant	River	State	Installed[1] capacity (KW)	Average annual generation (MWH)	Useable[2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
STUDY AREA A—Continued							
Northeast Utilities—Continued							
Hadley Falls Sta.	Connecticut	Mass.	17, 000	99, 598		52	
Riverside Station	Conn.-Canal	do.	7, 640	28, 674		30	
Boatlock Station	do.	do.	2, 900	15, 576		20	
Beebe-Holbrook	do.	do.	516	1, 726		20	
Skinner	do.	do.	250	625		20	
Chemical	do.	do.	1, 600	100		12	
Central Vermont Public Service Corp.:							
Pittsford	East Creek	Vermont	3, 600	6, 000	17. 500	481	
Glen	do.	do.	2, 000	4, 400	0. 035	170	
Patch	do.	do.	400	700	0. 140	30	
Hydeville	L. Bomoseen	do.	270	300	10. 300	40	
Carver Falls	Poultney	New York	1, 560	6, 100	0. 023	115	
Cavendish	Black	Vermont	1, 440	4, 900	0. 023	120	
Silver Lake	Leicester	do.	2, 200	4, 700	3. 000	670	
Salisbury	do.	do.	1, 300	2, 500	5. 151	160	
Middlebury Lower	Otter Creek	do.	2, 250	7, 400	0. 046	28	
Weybridge	do.	do.	3, 000	11, 600	0. 333	31	
Bradford	Waits	do.	360	1, 900	0. 023	75	
Taftsville	Ottaquechee	do.	500	1, 500	0. 030	20	
Fairfax	Lamoille	do.	2, 880	21, 100	0	86	
Clark Falls	do.	do.	3, 000	15, 600		43	
Milton	do.	do.	6, 000	35, 900	[7] 7. 000	100	
Peterson	do.	do.	5, 000	24, 400		54	
Pierce Mills	Passumpsic	do.	250	1, 500	0. 004	17	
Arnold Falls	do.	do.	350	1, 400	0. 005	17	
Gage	do.	do.	700	2, 500	0. 007	15	
Passumpsic	do.	do.	700	3, 900	0. 003	22	
West Dumerston	West	do.	720	1, 400	0. 058	24	
Hoosick Falls	Hoosic	New York	650	2, 800	0. 250	24	
Eastern Utilities Associates:							
Pawtucket.	Blackstone	R.I.	600	1, 400	N.A.	16	
Farmington River Power Company:							
Rainbow.	Farmington	Connecticut	8, 000	20, 000	N.A.	60	
Public Service Company of New Hampshire:							
Ayers Island	Pemigewassett	N.H.	8, 400	41, 357	6. 0	80	
Eastman Falls	do.	do.	3, 000	18, 241	0. 5	35	
Garvins	Merrimack	do.	7, 200	40, 001	0. 75	30	
Hooksett	do.	do.	1, 600	10, 700	None	14	
Amoskeag Hydro	do.	do.	16, 000	82, 702	2. 0	46	
J. Brodie Smith	Androscoggin	do.	15, 000	97, 608	None	83	
Gorham Hydro	do.	do.	2, 150	16, 556	Small	18	
Canaan	Connecticut	do.	1, 100	7, 500	Small	35	
Minnewawa	Minnewawa Br.	do.	1, 600	4, 000	Small	255	
Salmon Falls	Salmon Falls	do.	2, 000	6, 600	Small	45	
Jackman	Contoocook	do.	3, 200	9, 000	8. 7	168	
Kelleys	Piscataquoq	do.	1, 000	2, 100	Small	21	
Green Mountain Power Corporation:							
Marshfield	Molly's Brook	Vermont	5, 000	6, 500	0. 414	380	
Little River	Waterbury	do.	5, 520	15, 500	36. 337	148	
Middlesex	Winooski	do.	3, 200	13, 500	0. 069	52	
Gorge	do.	do.	3, 000	14, 000	0. 401	34	
Essex	do.	do.	7, 200	31, 500	1. 653	65	

See footnote at end of table.

Existing Conventional Hydroelectric Plants—Continued

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
		STUDY AREA A—Continued					
Green Mountain Power Corporation—Continued							
Montpelier	Winooski	Vermont	600	2,000	0.014	60	....
Vergennes	Otter Creek	do	2,560	11,000	0.350	38	....
West Danville	Joe's Brook	do	1,000	3,000	1.200	180	....
Citizens Utilities Co.:							
Charleston	Clyde	do	800	4,000	0.400	57	....
Newport No. 1	do	do	4,000	14,000	1.000	140	....
Newport No. 2	do	do	1,600	5,000	1.000	55	....
Troy	Missisquoi	do	600	1,000	0.200	60	....
Vermont Marble Company:							
Center Rutland	Otter Creek	Vermont	300	1,300	0.002	32	....
Proctor	do	do	3,900	19,000	0.368	123	....
Beldens	do	do	1,600	8,500	0.076	42	....
Huntington	do	do	1,400	10,400	0.092	42	....
Enosburg Water and Light:							
Village No. 1	Missisquoi	do	600	3,100	0.015	21	....
Kendall	do	do	150	400	0.015	18	....
Morrisville Water and Light:							
Cadys Falls	Lamoille	do	1,300	5,000	0.500	42	....
Morrisville	do	do	1,800	7,500	0.020	52	....
Lyndonville Electric Plant:							
Vail	Passumpsic	do	350	1,700	0.018	18	....
Great Falls	do	do	600	4,400	0.030	61	....
Other Existing Plants in Study Area A:							
Bethel Mills	White	do	120	600	0	30	[10]
Lovejoy	Black	do	100	200	0	20	[11]
Fellows Gear	do	do	400	1,000	0	35	[12]
Hardwick	Lamoille	do	700	2,600	0.050	70	[13]
Barton	Clyde	do	1,400	4,000	0.100	75	[14]
Swanton	Missisquoi	do	4,600	20,000	0.100	60	[15]
Missisquoi	do	do	1,800	6,500	0.100	30	[16]
		STUDY AREA B					
Niagara Mohawk Power Corporation: [9]							
Hydraulic Race	Barge Canal	New York	4,687	16,774	0	50.0	....
Oak Orchard	do	do	350	1,427	0	25.0	....
Glenwood	Oak Orchard Cr	do	1,500	6,867	0.41	61.5	....
Waterport	do	do	4,650	11,508	5.025	80.0	....
Moshler	Beaver	do	8,000	37,566	8.115	212.7	....
Eagle	do	do	6,050	28,711	0.69	135.8	....
Soft Maple	do	do	15,000	31,556	2.678	125.8	....
Effley	do	do	2,960	12,283	3.14	53.9	....
Elmer	do	do	1,500	8,070	0.345	37.1	....
Taylorville	do	do	4,500	23,035	0.95	103.7	....
Belfort	do	do	1,800	9,213	0.12	48.1	....
High Falls	do	do	4,800	24,640	0.746	95.5	....
Beaver Falls	do	do	1,500	7,260	N.A.	29.3	[17]
Herrings	Black	do	5,400	21,805	0.67	19.5	....
Deferiet	do	do	10,800	52,426	0.405	47.0	....
Kemargo	do	do	5,400	24,866	0.359	27.0	....
Black River	do	do	6,000	31,860	0.128	34.1	....
Sewalls	do	do	2,000	10,706	0	16.7	....
Diamond Island	do	do	1,200	5,916	N.A.	9.0	....

See footnotes at end of table.

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
				STUDY AREA B—Continued			
Niagara Mohawk Power Corporation: [9]—Con.							
Beebee Island	Black	New York	8,000	32,417	0.142	33.5	(18)
Port Leyden	do.	do.	545	2,337	N.A.	21.0	(19)
Denley	do.	do.	496	3,776	N.A.	22.0	(19)
Watertown	do.	do.	5,400	20,474	N.A.	26.7	(20)
Dexter	do.	do.	1,860	12,078	N.A.	12.9	(21)
Theresa	Indian	do.	1,615	6,026	0.145	66.5	
Browns Falls	Oswegatchle	do.	15,000	45,935	2.22	270.0	
Flat Rock	do.	do.	6,000	14,347	3.382	60.0	
South Edwards	do.	do.	2,680	16,535	0.738	84.6	
Oswegatchie	do.	do.	560	4,146	0.023	33.8	
Heuvelton	do.	do.	1,040	4,876	0.405	13.1	
Eel Weir	do.	do.	2,700	8,495	0.136	12.5	
Mowlet	do.	do.	900	5,436	N.A.	22.0	(22)
Hallesboro	do.	do.	1,490	7,009	N.A.	30.0	(22)
Emeryville	do.	do.	2,030	8,007	N.A.	33.2	(23)
Natural Dam	do.	do.	1,120	5,609	N.A.	23.0	(24)
Riverside	Oswego	do.	800	5,923	0.161	23.5	(25)
Granby	do.	do.	3,722	17,153	0.161	24.5	
Fulton	do.	do.	1,250	4,762	0.161	17.5	
Minetto	do.	do.	8,000	29,440	0.198	17.3	
Varick	do.	do.	8,800	26,021	N.A.	19.6	
High Dam #6	do.	do.	7,100	33,669	0.318	20.8	(26)
Stark	Raquette	do.	22,500	76,215	11.43	104.7	
Blake	do.	do.	14,400	51,905	3.857	68.4	
Rainbow	do.	do.	22,500	82,589	9.435	102.3	
Five Falls	do.	do.	22,500	83,256	0.657	103.4	
South Colton	do.	do.	19,350	69,567	1.375	85.0	
Higley	do.	do.	4,480	26,774	4.446	45.8	
Colton	do.	do.	30,000	184,312	0.62	284.5	
Hannawa	do.	do.	7,200	50,437	0.69	81.0	
Sugar Island	do.	do.	4,800	27,693	0.055	63.0	
Norwood	do.	do.	2,000	14,684	1.735	20.6	
Yaleville	do.	do.	725	3,702	0.24	12.0	
E. Norfolk	do.	do.	3,000	23,735	0.36	31.9	
Norfolk	do.	do.	4,500	23,876	0.032	42.4	
Raymondville	do.	do.	2,000	13,898	0.265	22.1	
Piercefield	do.	do.	2,700	13,468	N.A.	35.0	
Hewittville	do.	do.	1,770	6,861	N.A.	19.0	(27)
Unionville	do.	do.	1,380	7,084	N.A.	21.6	(27)
Pyrites	Grasse	do.	1,500	8,474	N.A.	76.0	(21)
Parishville	W. Br., St. Regis.	do.	2,400	13,739	0.223	143.5	
Allens Falls	do.	do.	4,400	23,908	0.653	220.7	
Hogansburg	St. Regis	do.	700	3,043	N.A.	10.2	
Keeses Mill	do.	do.	125	0	N.A.	18.8	
Chasm	Salmon North	do.	3,350	21,404	0.03	268.3	
Macomb	do.	do.	1,000	5,546	0.014	52.9	
Bennette Bridge	Salmon South	do.	26,750	52,814	53.5	283.9	
Lighthouse Hill	do.	do.	7,500	19,691	1.81	65.0	
Franklin	Saranac	do.	2,265	7,731	N.A.	54.0	
Union	do.	do.	2,400	0	N.A.	63.0	
Baldwinsville	Seneca	do.	640	3,620	N.A.	8.0	

See footnotes at end of table.

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
			STUDY AREA B—Continued				
Niagara Mohawk Power Corporation: [9]—Con.							
Prospect	W. Canada Cr.	New York	17, 325	55, 548	0. 804	137. 5	
Trenton	do.	do.	23, 600	109, 750	0. 155	268. 0	
Middle Falls	Batten Kill	do.	1, 040	4, 837	0. 24	50. 0	
Ephratah	Caroga Cr.	do.	5, 150	11, 058	0. 43	294. 0	
Inghams	E. Canada Cr.	do.	6, 400	22, 385	2. 0	124. 5	
Beardslee	do.	do.	20, 000	37, 194	1. 2	156. 5	
Victory Mills	Fish Cr.	do.	1, 280	2, 683	0. 007	40. 0	
Schuylerville	do.	do.	1, 200	4, 680	0. 14	60. 0	
Johnsonville	Hoosic	do.	4, 800	8, 156	4. 6	35. 0	
Schaghticoke	do.	do.	13, 120	45, 072	0. 64	153. 0	
Spier Falls	Hudson	do.	44, 400	172, 094	3. 3	84. 3	
Sherman Island	do.	do.	28, 800	126, 176	1. 7	70. 3	
S. Glens Falls	do.	do.	3, 800	26, 874	0. 90	47. 6	
Moreau	do.	do.	4, 800	31, 682	0. 2	66. 0	
Bakers Falls	do.	do.	2, 250	15, 009	0. 2	66. 0	
Ft. Edward	do.	do.	2, 850	13, 960	0. 75	21. 6	
Mechanicville	do.	do.	4, 500	22, 182	0	17. 0	
Green Island	do.	do.	[28] 5, 000	N.A.	N.A.	10. 0	
Feeder Dam	do.	do.	6, 000	22, 494	N.A.	15. 0	([29])
Stuyvesant Falls	Kinderhook Cr.	do.	2, 800	5, 894	0. 11	100. 0	
School Street	Mohawk	do.	38, 800	144, 424	0. 24	96. 0	
Crescent	do.	do.	5, 600	33, 527	N.A.	28. 0	([30])
Vischers Ferry	do.	do.	5, 600	32, 484	N.A.	28. 0	([30])
E. J. West	Sacandaga	do.	20, 000	47, 756	N.A.	63. 0	
Stewarts Bridge	do.	do.	30, 000	93, 498	3. 100	100. 0	
New York State Electric and Gas Corporation:							
Kent Falls	Saranac	do.	6, 400	43, 202	0. 175	161	
Mill "C"	do.	do.	2, 250	14, 214	3. 155	66	
Cadyville	do.	do.	2, 400	17, 670	3. 625	77	
High Falls	do.	do.	14, 100	75, 066	0. 550	268	
Rainbow Falls	Ausable	do.	2, 640	13, 898	14. 000	92	
Colliers	Susquehanna	do.	3, 810	5, 395	0. 520	30	
Seneca Falls	Seneca	do.	8, 000	6, 697	0. 720	50	
Waterloo	Seneca Canal	do.	1, 920	2, 031	107. 000	17	
Keuka	Keuka Lake	do.	2, 000	4, 079	6. 000	380	
Power Authority of the State of New York:							
Robert Moses Power Dam.	St. Lawrence	do.	912, 000	[31] 6, 034, 059	N.A.	80–86	
Robert Moses Niagara.	Niagara	do.	[32] 1, 950, 000	[31] 12,497,034	N.A.	306	
Orange and Rockland Utilities:							
Swinging Bridge No. 1.	Mongaup	do.	5, 000	[33] 6, 250	17. 222	122	
Swinging Bridge No. 2.	do.	do.	6, 750	[34] 10, 104	17. 222	122	
Mongaup	do.	do.	4, 000	[33] 15, 840	0. 706	115	
Rio	do.	do.	10, 000	[33] 29, 715	1. 837	185	
Grahamsville	do.	do.	18, 000	[35] 72, 941	([36])	440	
Rochester Gas and Electric Corp.:							
Rochester No. 2	Genesee	do.	6, 500	43, 700	([37])	92. 6	
Rochester No. 5	do.	do.	38, 250	157, 000	([37])	137	
Rochester No. 26	do.	do.	3, 000	14, 560	([37])	29	

See footnotes at end of table.

Name of plant	River	State	Installed [1] capacity (KW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status
			STUDY AREA B—Continued				
Rochester Gas and Electric Corp—Continued							
Mt. Morris No. 160	Genesee	New York	340	2, 380	(37)	20	....
Wiscoy No. 170	Wiscoy Cr	do	1, 080	4, 540	(37)	104	....
Mills No. 172	do	do	220	870	(37)	58	....
Central Hudson Gas and Electric Corp.:							
Dashville	Walkill	do	4, 800	18, 000	(37)	42	....
Sturgeon Pool	do	do	14, 400	54, 500	(37)	113	....
High Falls	Rondout Cr	do	2, 120	7, 200	(37)	48	....
Neversink	Neversink Div	do	25, 000	48, 000	109	552	....
Village of Springville (N.Y.):							
Cattaraugus Creek	Cattaragus Creek.	do	500	2, 000	....	30	....
Other Existing Plants in Study Area B:							
Philadelphia Muni	Indian	do	128	300	N.A.	20	....
Potsdam Muni	Raquette	do	187	800	N.A.	9	....
Theresa Muni	Indian	do	130	500	N.A.	15	....
Gouverneur Muni	Oswegatchie	do	160	1, 200	N.A.	7	....
Lake Placid Muni	Chubb	do	332	600	N.A.	35	....
			STUDY AREA C				
General Public Utilities:							
Oakland	Susquehanna	Pennsylvania	600	849	....	9. 0	(38)
Raystown	Raystown Br. Juniata	do	2, 100	9, 645	1. 7	40. 0	....
Warrior Ridge	Little Juniata	do	2, 000	7, 848	....	26. 0	....
Piney	Clarion	do	28, 800	74, 836	13. 0	83. 4	....
Deep Creek	Youghiogheny	Maryland	19, 200	29, 992	92. 9	437. 0	....
York Haven	Susquehanna	Pennsylvania	19, 620	102, 000	2. 0	22. 5	....
Pennsylvania Power and Light Co.							
Holtwood	do	do	[3] 107, 200	581, 500	19. 0	51. 0	....
Wallenpaupack	Lackawaxen	do	40, 000	77, 600	158. 0	370. 0	....
Safe Harbor Water Power Corp.:							
Safe Harbor	Susquehanna	do	[3] 230, 000	918, 000	68. 9	54. 0	....
Passaic Valley Water Commission:							
Little Falls	Passaic	New Jersey	2, 400	5, 000	....	36	....
City of Paterson, New Jersey:							
SUM	do	do	3, 680	5, 000	....	67. 0	(39)
Philadelphia Electric Company and Subsidiary:							
Conowingo Hydro Electric Plant.	Susquehanna	Maryland	474, 480	1, 690, 000	81. 0	89. 0	....

[1] Capacities include main generating units only and are given as reported by the plant owners. Several plants have auxiliary generating capacity.

[2] Useable power storage at the site of the hydro station.

[3] Enlargement of existing plant at this location is possible. See "Undeveloped Conventional Hydroelectric Plants".

[4] Generation during 1966.

[5] Usable power storage is reported by Connecticut Light and Power Co.

[6] Estimated average annual generation based on year ot median flow.

[7] Reservoir serves more than one plant.

[8] Leased to Northeast Utilities by City of Springfield.

[9] Average annual generation covers the years 1962 through 1966 for the Niagara Mohawk system.

[10] Owned by Bethel Mills, Inc.

[11] Owned by Lovejoy Tool Company.

[12] Owned by Fellows Gear Shaper Co.

[13] Owned by Hardwick Electric Light.

[14] Owned by Barton Village.

[15] Owned by Swanton Electric Light.

[16] Owned by Missisquoi Paper Co.

[17] Owned by J. P. Lewis Company. Generation made available to the Niagara Mohawk system.

[18] Owned by Beebee Island Corp.

Footnote continued on following page.

Footnote continued from previous page.

[19] Owned by Cataldo Electric Service. Generation made available to the Niagara Mohawk system.

[20] Owned by Watertown Municipal Electric Department. Generation made available to the Niagara Mohawk system.

[21] Owned by Dexter Hydroelectric Corp. Generation made available to the Niagara Mohawk system.

[22] Owned by International Talc Co. Generation made available to the Niagara Mohawk system.

[23] Owned by Hampshire Paper Mills, Inc. Generation made available to the Niagara Mohawk system.

[24] Owned by Groverton Papers Co. Generation made available to the Niagara Mohawk system.

[25] Owned by Sealright Oswego Corp. and operated by Niagara Mohawk under leasing agreement.

[26] Owned by City of Oswego and operated by Niagara Mohawk under leasing agreement.

[27] Owned by Nekoosa Edwards Paper Co. Generation made available to the Niagara Mohawk system.

[28] Estimated capacity after rehabilitation.

[29] Owned by Moreau Manufacturing Co. Generation made available to the Niagara Mohawk system.

[30] Owned by State of New York, Department of Transportation. Generation made available to the Niagara Mohawk system.

[31] Gross generation, 1966 calendar year.

[32] Conventional hydro only. See "Existing Pumped Storage Plant," for Lewiston plant.

[33] Based on 30 year average.

[34] Based on 28 year average.

[35] Based on 11 year average.

[36] Grahamsville plant is on Pepacton Reservoir of the New York City Department of Water Supply, Gas and Electricity. The limit of drawdown is not determinable by the owner of the Grahamsville plant.

[37] Usable power storage less than 5,000 acre feet.

[38] Application for surrender of FPC license and abandonment of plant is pending.

[39] Owned by City of Paterson, New Jersey and leased by Public Service Electric and Gas Co.

NOTE.—N.A.—Data not available.

Undeveloped Pumped Storage Sites

Name	River	Installed [1] capacity (MW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status	Cost range ($/kw) 60–80	80–100	100–120
			STUDY AREA A						
Maine:									
Rowe	Kennebec	1,000	[3] 440,000	24.1	785	A	X		
Rangley	Androscoggin	1,000	440,000	26.1	940	U	X		
Moosehead	Piscataquis	1,000	440,000	3.7	1,958	U		X	
New Hampshire:									
Fall Mountain	Connecticut	[4] 750	N.A.	11.0	652	A		X	
Wantastiqueot	do.	[6] 450	N.A.	2.3	1,140	A	X		
Mascoma	Mascoma L.-Smith Pond.	[4] 275	N.A.	2.2	920	U			X
Indian Pond	Connecticut	700	N.A.	12.0	815	U			X
Shelburne	Androscoggin	1,000	N.A.	N.A.	1,500	U		N.A.	
Gorham	do.	350	N.A.	N.A.	1,200	U		N.A.	
Site A	do.	1,200	N.A.	N.A.	1,935	U		N.A.	
Site B	N. Branch Contoocook.	525	N.A.	N.A.	450	U		N.A.	
Site C	S. Branch Ashuelot.	500	N.A.	N.A.	600	U		N.A.	
Vermont:									
Roaring Brook	Roaring Brook	[4] 645	N.A.	N.A.	820	U			X
Tiny Pond	Tiny Pond Rescue L.	[5] 550	N.A.	4.6	836	U			X
Halls Lake	Connecticut	[5] 550	N.A.	9.0	415	U			X
Massachusetts:									
Bear Swamp	Deerfield	[5] 600	N.A.	4.8	770	A	X		
North Mountain	Cheshire Res.	500	N.A.	5.5	1,130	U			X
East Mountain	3-Mile Pond	[4] 800	N.A.	10.5	800	U	X		
Hemenway Swamp	Quabbin Res.	[4] 900	N.A.	18.0	490	U		X	
State Line	Deerfield	[4] 350	N.A.	3.0	810	U		X	
Northfield Mountain.[7]	Connecticut	1,000	832,800	12.750	824	C [7]	X		
Massachusetts A	Housatonic	3,000	N.A.	29.60	1,190	A–U		X	
Massachusetts B	do.	2,000	N.A.	24.0	1,552	A–U		X	
Connecticut:									
Connecticut A	do.	2,000	N.A.	40.4	955	A–U		X	
Connecticut B	do.	2,000	N.A.	35.3	1,066	A–U		X	
			STUDY AREA B						
New York:									
Cornwall	Hudson	[8] 2,000	1,000,000	25	1,160	A [9]	X		
Ripley	L. Erie	[10] 1,200	N.A.	16.7	988	U		X	
Bristol Springs	Honeoye Inlet	[10] 1,000	N.A.	15.2	906	U		X	
Gilboa	Schoharie Creek.	[10] 1,000	N.A.	12.9	1,075	A		X	
Whitehall	L. Champlain (South Bay).	[10] 1,000	N.A.	12.8	950	U		X	
South Hill	Canandaigua Lake.	[10] 1,000	N.A.	11.4	1,221	U		X	
Copake	Noster Kill and Webatuck Cr.	[10] 1,000	N.A.	14.5	950	U		X	
Gardiner	Shawangunk Kill.	[10] 1,000	N.A.	11.1	1,246	U			X
Napanoch	do.	[10] 1,000	N.A.	9.6	1,440	U			X
Three Ponds	L. George	[5] 280	N.A.	N.A.	941	U		N.A.	
Crossett Pond	do.	[5] 1,000	N.A.	N.A.	1,221	U		N.A.	
Jabe Pond	do.	[5] 190	N.A.	N.A.	990	U		N.A.	
Lake Bonita	Hudson	[5] 100	N.A.	N.A.	440	U		N.A.	
Lake Ann	do.	[5] 158	N.A.	N.A.	624	U		N.A.	

See footnotes at end of table.

Undeveloped Pumped Storage Sites—Continued

Name	River	Installed [1] capacity (MW)	Average annual generation (MWH)	Useable [2] power storage (1,000 Ac-ft.)	Gross static head (feet)	Status	Cost range ($/kw) 60–80	80–100	100–120
			STUDY AREA B—Continued						
New York—Continued									
Grant Mtn	Hudson	[5] 63	N.A.	N.A.	644	U		N.A.	
Skaneateles	Skaneateles Lake.	[5] 440	N.A.	N.A.	915	U		N.A.	
N–4	Middle Brook	382	650,000	8.8	555.0	U		X	
N–7	Elk Creek	593.5	1,010,000	11.0	685.0	U			X
N–10	Charlotte Cr	571	970,000	11.0	659.0	U		X	
O–27	Butternut Cr	566	960,000	10.0	719.0	U		X	
			STUDY AREA C						
New Jersey:									
Longwood Valley	Rockaway	[1] 135	225,000	3.3	382.5	A [11]			X
Kittatinny Mtn	Delaware	[12] 1,300	2,250,000	16.0	1,100.0	A	X		
Pennsylvania:									
Kinzua Project	Allegheny	355	550,000	6.5	665	C			X
Stony Creek	Stony Creek	1,110	972,000	15.0	975.0	A			X
F–3	do	830	1,410,000	12.3	865.0	U		X	
H–43	Sideling Creek	750	1,280,000	7.6	1,290.0	U		X	
H–46	do	645	1,100,000	8.0	1,048.0	U		X	
G–13	Conadoquinet Creek.	620	1,050,000	9.5	844.0	U		X	
G–21	Aughwick Cr	410	700,000	6.0	871.0	U		X	
F–16	Mahanoy Cr	790	1,340,000	9.2	812.0	U		X	
G–6	Honey Creek	515	880,000	6.4	1,050.0	U		X	
M–9	Wycoff Run	1,370	2,320,000	15.8	1,057.0	U		X	
M–12	do	610	1,040,000	8.8	915.0	U		X	
M–13A	Mix Run	742	1,260,000	8.0	1,172.0	U		X	
M–14	do	630	1,070,000	8.0	1,002.0	U		X	
K–5	Mehoopany Cr	1,000	1,700,000	10.0	1,262.0	U		X	
K–13	Towanda Creek	540	920,000	7.0	1,009.0	U		X	
K–17	Shader Brook	530	900,000	7.8	870.0	U		X	
K–36	Mehoopany Cr	1,750	2,980,000	17.5	1,270.0	U		X	
B–6	Susquehanna	200	340,000	7.0	368.0	U		X	
G–22A	Doubling Gap Run.	456	780,000	6.7	876.0	U		X	
G–30A	Standing Stone Creek.	900	1,530,000	16.2	709.0	U		X	
M–31	G. B. Stevenson Reservoir.	630	1,070,000	7.4	1,130.0	U		X	
L–42	Kettle Creek	270	460,000	2.8	1,225.0	U			X

[1] Installed capacity, based on 10 hours full-load use of storage, except as noted. Further studies necessary at undeveloped sites to determine proper relationship between storage and installed capacity.

[2] Power storage for undeveloped sites is the largest feasible, as controlled by either the upper or the lower reservoir.

[3] 5% annual load factor.

[4] Based on 8 hours full-load use of storage. (Ref. Note 1)

[5] Based on 6 hours full-load use of storage. (Ref. Note 1)

[6] Based on 4 hours full-load use of storage. (Ref. Note 1)

[7] Installed capacity based on useable storage of 8500 MWH and a weekly cycle for refilling the upper reservoir. Studies currently being made to determine ultimate capacity. The 832,000 MWH shown under "Average Annual Generation" is an estimated average for the first 6 years of operation. Thereafter, the average annual generation is estimated to be 1,500,000 MWH. FPC license has been granted, project is under construction.

[8] Net dependable capacity.

[9] License pending decision of Federal Power Commission—Project No. 2338.

[10] Based on 12 hours full-load use of storage. (Ref. Note 1)

[11] Work confined to mechanical equipment pending approval of FPC license application.

[12] Combined conventional and pumped storage. Based on about 11 hours full-load use of storage.

Notes.—N.A.—Data not available; A—Plants under active consideration; U—Undeveloped, but potential site; C—Under construction.

Existing Pumped Storage Plants

Name	River	State	Installed capacity (MW)	Average annual generation (MWH)	Useable power storage (1,000 Ac-ft.)	Gross static head (feet)	Cost Range ($/KW)		
							80–80	60–100	100–120
STUDY AREA A									
Northeast Utilities									
Rocky River.[1]	Housatonic.	Conn.	[1] 31	[1] 12,750	142.560	230			([2])
STUDY AREA B									
Power Authority of the State of New York									
Lewiston Pump—Generating Plant.	Niagara	New York	240	[3] 420,773	60.0	65–100			([2])
STUDY AREA C									
Public Service Electric and Gas, General Public Utilities									
Yards Creek.	Yards Cr.	New Jersey	[4] 330	[5] 520,000	4.7	887.6		X	
Philadelphia Electric Co.									
Muddy Run Pump—Storage Generating Plant.	Susquehanna.	Penna.	800	[5] 1,300,000	33.2	411–361		X	

[1] Plant differs from day-night plant in that operation is on a seasonal basis and the upper reservoir receives substantial run-in-from 40.4 square mile drainage area. Installed capacity is based on one conventional generator, rated at 24 Mw, and two reversible pump-generators rated at 3.5 Mw each. "Average Annual Generation" derived from net run-in to upper reservoir is estimated at 6,750 MWH, and generation derived from pumped water is estimated at 6,000 MWH.

[2] Cost was in excess of $120/KW.

[3] Net generation, 1966 calendar year. Operates in conjunction with Robert Moses Niagara Power Plant.

[4] Based on 8.4 hour full-load use of storage.

[5] Estimated.

Gas Turbine and Internal Combustion Peaking Units

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
STUDY AREA A								
Maine Public Service:								
Caribou Unit No. 1	IC	1.00	0.8	No. 2 oil	N.A.	1947	327	Manual.
Caribou Unit No. 2	IC	2.55	.8	do.	N.A.	1948	225	Do.
Caribou Unit No. 3	IC	2.55	.8	do.	N.A.	1948	225	Do.
Caribou Unit No. 4	IC	1.00	.8	do.	N.A.	1948	360	Do.
Caribou Unit No. 5	IC	1.00	.8	do.	N.A.	1951	720	Do.
Flo's Inn	IC	6.0	.8	do.	11,145	1959	900	Auto.
Houlton	IC	1.0	.8	do.	N.A.	1949	360	Manual.
Bangor Hydro-Electric Co.:								
East Machias	IC	2.0	.8	do.	10,430	1949	327	Manual.
Eastport No. 1	IC	1.0	.8	do.	10,430	1949	327	Do.
Eastport No. 2	IC	1.0	.8	do.	10,430	1949	327	Do.
Eastport No. 3	IC	2.0	.8	do.	10,780	1962	900	Auto.
Milford	IC	2.0	.8	do.	10,430	1949	327	Manual.
Medway	IC	8.0	.8	do.	10,500	1960	900	Do.
Bar Harbor	IC	8.0	.8	do.	10,920	1961	900	Auto.
Graham Station No. 1	GT	6.0	.8	do.	14,180	1950	3,600	Manual.
Graham Station No. 2	GT	6.0	.8	do.	14,180	1952	3,600	Do.

Gas Turbine and Internal Combustion Peaking Units—Continued

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
STUDY AREA A—Continued								
Central Maine Power Co.:								
Farmingdale	GT	4.0	.8	No. 2 oil	22,200	1950	3,600	Manual.
Rockland	IC	2.0	.8	do	11,057	1948	720	Do.
Peaks Island No. 1	IC	0.24	.8	do	11,057	1940	460	Do.
Peaks Island No. 2	IC	1.0	.8	do	11,057	1948	360	Do.
Peaks Island No. 3	IC	0.52	.8	do	11,057	1942	327	Do.
Isleboro No. 1	IC	0.13	.8	do	11,057	1963	1,200	Do.
Isleboro No. 2	IC	0.13	.8	do	11,057	1966	1,200	Do.
Lubec (Maine) Water and Electric District.								
	IC	0.9	.7	do	12,500	1952	720	Do.
	IC	0.2	.7	do	12,500	1941	300	Do.
	IC	0.2	.7	do	12,500	1942	450	Do.
United Illuminating Company:								
Bridgeport: Harbor	GT	18.5	.85	Jet "A"	13,650	1967	3,600	Semiauto.
New England Gas and Electric Association:								
Provincetown	IC	2.8	.8	Diesel oil	10,300	1968	900	Standby and Peaking.
	IC	0.42	.8	do	13,485	1934	400	Do.
	IC	0.24	.8	do	13,485	1929	257	Do.
	IC	0.24	.8	do	13,485	1929	257	Do.
	IC	0.12	.8	do	13,485	1938	400	Do.
	IC	0.15	.8	do	13,485	1938	400	Do.
New England Electric System:								
South County	IC	5.0	.8	No. 2 oil	10,440	1952	720	Manned.
South County	IC	5.0	.8	do	10,440	1954	514	Do.
Gloucester	IC	10.0	.8	do	9,870	1963–1964	900	Automatic.
Brayton Point	IC	11.0	.8	do	10,000	1966–1967	900	Do.
South St	IC	5.5	.8	do	10,000	1967	900	Do.
Gloucester	IC	11.0	.8	do	10,000	1967	900	Do.
Lynnway	IC	22.0	.8	do	10,000	1968	900	Do.
Boston Edison Company:								
"L" Street.	GT	18.6	.85	Oil	12,560	1966	3,600	Do.
Public Service Company of New Hampshire:								
Swans Falls	IC	3.0	.8	do	12,510	1942	720	Manual.
White Lake	GT	18.6	.85	Jet	17,650	1968	3,600	Automatic.
Merrimack	GT	18.6	.85	do	17,650	1968	3,600	Do.
Eastern Main Electric Cooperative, Inc.:								
Calais (1–4)	IC	1.2	.85	No. 2 oil	N.A.	1948	600	Standby.
Calais (5)	IC	1.0	.85	do	N.A.	1934	720	Do.
Calais (Portable)	IC	0.3	.85	do	N.A.	1960	1,200	Emergency.
Vinalhaven Light and Power Co.:								
Vinalhaven.	IC	0.17	.8	do	N.A.	1948	N.A.	Manual.
	IC	0.25	.8	do	N.A.	1954	N.A.	Do.
	IC	0.35	.8	do	N.A.	1959	N.A.	Do.
	IC	0.07	.8	do	N.A.	1939	N.A.	Do.
	IC	0.39	.8	do	N.A.	1964	N.A.	Do.
Citizens Utilities Company:								
Newport No. 1	IC	1.1	N.A.	do	10,900	1954	720	Do.
Newport No. 2	IC	1.1	N.A.	do	10,900	1954	720	Do.
Newport No. 3	IC	1.1	N.A.	do	10,900	1954	720	Do.
Newport No. 4	IC	0.92	N.A.	do	10,900	1948	720	Do.
Newport No. 5	IC	0.92	N.A.	do	10,900	1948	720	Do.

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
				STUDY AREA A—Continued				
Citizens Utilities Company—Continued								
Newport No. 6	IC	0.92	N.A.	Manual	10,900	1948	720	Manual.
Newport No. 7	IC	0.92	N.A.	do	10,900	1948	720	Do.
Enosburg Falls No. 1	IC	0.20	N.A.	do	10,900	1938	300	Do.
Enosburg Falls No 2	IC	0.69	N.A.	do	10,900	1949	300	Do.
Hardwick, Village of	IC	0.675	N.A.	do	10,900	1948	720	Do.
Newport (R.I.) Electric Corp.:								
Jepson	IC	2.0	.8	Diesel oil	10,425	1960	900	Remote.
	IC	2.0	.8	do	10,425	1960	900	Do.
	IC	2.0	.8	do	10,425	1961	900	Do.
	IC	2.0	.8	do	10,425	1961	900	Do.
Hudson (Mass.) Light and Power Dept.:								
Cherry Street No. 5	IC	1.0	.80	Oil	11,800	1937	277	Manual.
Cherry Street No. 7	IC	3.3	.75	do	10,700	1951	225	Do.
Cherry Street No. 8	IC	4.0	.75	Oil/N.G.	9,970	1955	240	Do.
Cherry Street No. 9	IC	3.25	.95	do	9,880	1960	240	Do.
Cherry Street No. 10	IC	2.0	.80	do	10,360	1962	720	Auto/Manual.
Cherry Street No. 11	IC	2.0	.80	do	10,360	1962	720	Do.
Cherry Street No. 12	IC	4.3	.80	do	9,200	1962	400	Do.
Peabody (Mass.) Municipal Light Plant.								
	IC	2.25	.80	No. 2/No. 5	N.A.	1948	225	N.A.
	IC	2.25	.80	do	N.A.	1949	225	Do.
	IC	2.25	.80	do	N.A.	1949	225	Do.
	IC	4.40	.80	No. 2/N.G.	N.A.	1966	257	Do.
South Norwalk (Conn.) Electric Works:								
No. 2	IC	2.0	.8	No. 2 oil	9,900	1940	225	Peaking.
No. 3	IC	2.0	.8	do	9,900	1942	225	Do.
No. 4	IC	3.0	.8	do	10,200	1951	225	Do.
No. 5	IC	3.2	.8	do	10,200	1960	240	Do.
Island Light and Power	IC	0.03	.8	do	N.A.	1946	N.A.	Manual.
	IC	0.12	.8	do	N.A.	1948	N.A.	Do.
	IC	0.25	.8	do	N.A.	1952	N.A.	Do.
	IC	0.18	.8	do	N.A.	1958	N.A.	Do.
	IC	0.40	.8	do	N.A.	1959	N.A.	Do.
	IC	0.50	.8	do	N.A.	1965	N.A.	Do.
Nantucket Gas and Electric Co.	IC	0.70	.8	do	N.A.	1948	N.A.	Do.
	IC	1.25	.8	do	N.A.	1953	N.A.	Do.
	IC	1.50	.8	do	N.A.	1957	N.A.	Do.
	IC	1.50	.8	do	N.A.	1963	N.A.	Do.
	IC	3.00	.8	do	N.A.	1966	N.A.	Do.
Wolfeboro Mun. Electric Dept.	IC	1.14	.8	do	N.A.	1955	N.A.	Do.
	IC	0.24	.8	do	N.A.	1928	N.A.	Do.
	IC	0.30	.8	do	N.A.	1938	N.A.	Do.
	IC	0.56	.8	do	N.A.	1942	N.A.	Do.
	IC	0.78	.8	do	N.A.	1950	N.A.	Do.
Northeast Utilities:								
South Meadow	GT	10.0	.8	JP-5	14,200	1962	3,600	Peaking.
Middletown No. 4	GT	20.0	.85	JP-5	11,800	1966	3,600	Peaking, Sta. A.
Norwalk No. 3	GT	16.3	.9	No. 2 oil	14,100	1966	900	Do.
Devon No. 9	GT	16.3	.9	do	14,100	1966	900	Do.
Torrington	GT	20.0	.85	JP-5	11,800	1967	3,600	Peaking.
Tracy	GT	16.0	.85	No. 2 oil	15,210	1967	3,600	Do.
E. Springfield	GT	16.0	.85	do	15,210	1967	3,600	Do.

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
				STUDY AREA A—Continued				
Northeast Utilities—Continued								
Franklin	GT	20.0	.85	JP-5	11,800	1968	3,600	Peaking, Sta. A.
W. Springfield No. 4	GT	20.0	.85	do	11,800	1968	3,600	Do.
Enfield	GT	20.0	.85	do	11,800	1969	3,600	Peaking.
Tunnel	GT	20.0	.85	do	11,800	1969	3,600	Do.
Brandford	GT	20.0	.85	do	11,800	1969	3,600	Do.
Woodland	GT	20.0	.85	do	11,800	1969	3,600	Do.
Thompsonville No. 1	GT	6.0	.8	No. 2/Gas	14,900	1953	3,600	Do.
Thompsonville No. 2	GT	6.0	.8	do	14,900	1953	3,600	Do.
Danielson No. 1	GT	6.0	.8	do	14,900	1953	3,600	Do.
Danielson No. 2	GT	6.0	.8	do	14,900	1953	3,600	Do.
Montville	IC	2.75	.8	No. 2 oil	20,900	1966	900	Peaking, Sta. A.
	IC	2.75	.8	do	20,900	1966	900	Do.
Holyoke Gas and Electric Dept.	GT	10.0	.8	JP-5	14,200	1964	3,600	Automatic.
Town of Ipswich, Mass., Municipal Light Dept.:								
High Street	IC	0.51	.8	No. 2 oil	N.A.	1930	300	Manual.
	IC	0.60	.8	do	N.A.	1937	257	Do.
	IC	0.73	.8	do	N.A.	1941	300	Do.
	IC	1.00	.8	do	N.A.	1960	600	Do.
	IC	1.14	.8	do	N.A.	1948	720	Do.
	IC	1.14	.8	do	N.A.	1951	720	Do.
	IC	1.36	.8	do	N.A.	1954	720	Do.
	IC	1.36	.8	do	N.A.	1956	720	Do.
	IC	1.36	.8	do	N.A.	1961	720	Do.
Braintree (Mass.) Electric Light Dept.:								
Main St. No. 1	IC	2.665	.8	do	10,500	1963	900	Auto-Remote.
Main St. No. 2	IC	2.665	.8	do	10,500	1963	900	Do.
Marblehead (Mass.) Municipal Light Dept.	IC	1.14	.8	Oil	N.A.	1948	720	Direct.
Central Vermont Public Service:								
Rutland No. 1	GT	6.0	.8	No. 2/No. 6	12,150	1951	3,600	Manual.
Rutland No. 2	GT	6.0	.8	do	12,150	1952	3,600	Do.
Rutland No. 3	GT	6.0	.8	do	11,850	1953	3,600	Do.
Rutland No. 5	GT	13.2	.85	do	15,300	1962	3,600	Do.
Ascutney	GT	13.2	.85	No. 2	15,600	1961	3,600	Automatic.
St. Albans No. 1	IC	1.25	1.00	do	11,400	1950	720	Manual.
St. Albans No. 2	IC	1.25	1.00	do	11,400	1950	720	Do.
Green Mountain Power Corp.:								
Gorge	GT	17.0	.85	do	15,080	1965	3,600	Automatic.
Essex No. 1	IC	1.0	.8	do	10,900	1947	720	Manual.
Essex No. 2	IC	1.0	.8	do	10,900	1947	720	Do.
Essex No. 3	IC	1.0	.8	do	10,900	1947	720	Do.
Essex No. 4	IC	1.0	.8	do	10,900	1947	720	Do.
Vergennes No. 1	IC	2.0	.8	do	10,300	1963	900	Do.
Vergennes No. 2	IC	2.0	.8	do	10,300	1964	900	Do.
Barton Village:								
Barton No. 1	IC	0.35	.8	do	10,900	1956	1,200	Do.
Barton No. 2	IC	0.35	.8	do	10,900	1956	1,200	Do.
Barton No. 3	IC	0.35	.8	do	10,900	1956	1,200	Do.
Barton No. 4	IC	0.35	.8	do	10,900	1956	1,200	Do.

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Gas Turbine and Internal Combustion Peaking Units—Continued

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
STUDY AREA A—Continued								
Swan's Island Electric Coop.:								
Minturn.	IC	0.10	.8	Oil	N.A.	1950	N.A.	N.A.
	IC	0.10	.8	do	N.A.	1950	N.A.	Do.
	IC	0.15	.8	do	N.A.	1965	N.A.	Do.
STUDY AREA B								
Niagara Mohawk Power Corp.:								
Albany	IC	.7	.8	No. 1 diesel	12,400	1967	1,200	Manual.
Dunkirk	IC	.7	.8	do	12,400	1967	1,200	Do.
Huntley	IC	.7	.8	do	12,400	1967	1,200	Do.
Oswego	IC	.7	.8	do	12,400	1967	1,200	Do.
Nine Mile	IC	2.5	.8	No. 2 diesel	11,120	1967	900	Do.
Nine Mile	IC	2.5	.8	do	11,120	1967	900	Do.
New York State Electric and Gas Corp.:								
Deerland Unit 1	IC	.12	.8	Oil	12,405	1929	257	Manual.
Deerland Unit 2	IC	.12	.8	do	15,162	1929	257	Do.
Deerland Unit 3	IC	.148	.8	do	10,578	1939	300	Do.
Deerland Unit 4	IC	.1	.8	do	18,195	1947	1,200	Do.
Deerland Unit 5	IC	.2	.8	do	17,058	1950	1,200	Do.
Gadyville Unit 1	IC	.76	.8	do	11,372	1947	600	Do.
Gadyville Unit 2	IC	.76	.8	do	10,580	1947	600	Do.
Gadyville Unit 3	IC	.76	.8	do	10,511	1947	600	Do.
Milliken Unit A	IC	2.75	.8	do	10,170	1967	900	Semiauto.
Milliken Unit B	IC	2.75	.8	do	10,170	1967	900	Do.
Harris Lake	IC	2.0	.8	do	10,238	1967	900	Automatic.
Rochester Gas and Electric Co.:								
Station 37	GT	18.00	.8	do	13,850	1968	3,600	Manual.
	GT	16.65	.8	do	14,250	1968	3,600	Do.
	GT	18.75	.8	do	14,500	1968	3,600	Do.
City of Plattsburgh	IC	2.10	.8	No. 2 oil	N.A.	1941	225	Emergency Standby.
	IC	1.14	.8	do	N.A.	1953	720	Do.
Village of Skaneateles Municipal Electric Dept.								
	IC	0.38	.8	do	N.A.	1941	600	Manual.
Long Island Lighting:								
Montauk	IC	4	.8	do	10,250	1961	900	Supervisory.
East Hampton	IC	8	.8	do	10,250	1962	900	Do.
Southampton	GT	11.5	.85	do	16,100	1963	3,600	Do.
Southold	GT	14	.85	do	15,230	1964	3,600	Do.
West Babylon	GT	55.8	.85	do	13,520	1966	3,600	Do.
E. F. Barrett APG	GT	18.6	.85	do	13,520	1966	3,600	Remote Panel.
Glenwood APG	GT	16	.85	Oil/NG	14,740	1967	3,600	Supervisory.
Northport APG	GT	16	.85	No. 2 oil	14,740	1967	3,600	Remote Panel.
Port Jefferson APG	GT	16	.85	do	14,740	1966	3,600	Supervisory.
Consolidated Edison Company of New York:								
	GT	15.25	.85	NG	15,600	1967	5,100	Remote and Local.
Astoria.								
Ravenswood	GT	15.25	.85	do	15,600	1967	[4]5,100	Do.
74th Street	GT	35.0	.85	No. 2 oil	7,290		[4]8,650	Do.
Hudson Ave	GT	34.9	.8	do	7,500		[4]8,650	Do.
59th Street	GT	34.8	.8	do	7,500		[4]8,000	Do.
Indian Point	GT	21	.85	do	14,250		[4]4,910	Do.
Kent Avenue	GT	24	.8	do	6,670		[4]8,000	Do.
Waterside	GT	12	.8	do	6,670		[4]8,000	Do.

See footnotes at end of table.

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
STUDY AREA B—Continued								
Greenport Electric Department:								
Greenport Plant	IC	0.42	.8	No. 1 diesel	(2)	1929	225	Manual.
	IC	0.27	.8	do		1927	225	Do.
	IC	0.72	.8	do		1948	720	Do.
	IC	1.25	.8	Nat. gas		1957	360	Do.
	IC	1.875	.8	do		1964	360	Do.
	IC	1.00	.8	do		1941	300	Do.
Rockville Centre Electric Dept.:								
Rockville Centre	IC	2.0	.8	No. 2–4 oil	10,000	1932	120	Do.
	IC	2.0	.8	do	10,000	1936	120	Do.
	IC	2.0	.8	do	10,000	1942	225	Do.
	IC	2.7	.8	do	10,000	1950	225	Do.
	IC	3.2	.8	Nat. gas	10,000	1954	225	Do.
	IC	3.2	.8	do	10,000	1954	225	Do.
	IC	5.2	.8	do	10,000	1962	240	Do.
	IC	6.4	.8	do	10,000	1967	257	Do.
Village of Freeport Electric Department:								
Plant No. 1:								
Unit No. 9	IC	2.14	.8	No. 2 oil	N.A.	1941	240	Do.
Unit No. 10	IC	2.72	.8	No. 6 oil	N.A.	1949	225	Do.
Unit No. 11	IC	3.10	.8	do	10,314	1953	257	Do.
Unit No. 12	IC	5.15	.8	do	10,000	1964	240	Do.
Plant No. 2:								
Unit No. 1	IC	10.0	N.A.	do	9,500	1969	124.14	Do.
Unit No. 2	IC	10.0	N.A.	do	9,500	(3)	124.14	Do.
Central Hudson Gas and Electric:								
Danskammer Unit 5	IC	2.75	.8	Diesel	10,420	1967	900	Peaking.
Danskammer Unit 6	IC	2.75	.8	do	10,420	1967	900	Do.
Lawrence Park Heat, Light, and Power Co.:								
Bronxville	IC	0.25	.8	Diesel	N.A.	1948	N.A.	Manual.
STUDY AREA C								
Public Service Electric and Gas Co.:								
Essex	GT	30	.85	Gas	18,150	1963	3,600	Peaking.
Sewaren	GT	115.2	.90	do	15,170	1965	3,600	Do.
Kearny	GT	18.6	.85	do	13,650	1967	3,600	Do.
Bergen	GT	18.6	.85	do	13,650	1967	3,600	Do.
Linden	GT	18.6	.85	do	13,650	1967	3,600	Do.
Burlington	GT	18.6	.85	Kerosene	13,650	1967	3,600	Do.
Mercer	GT	115.2	.9	Gas	15,170	1967	3,600	Do.
Hudson	GT	115.2	.9	do	15,170	1967	3,600	Do.
Kearny	GT	115.2	.9	do	15,170	1969	3,600	Do.
Kearny	GT	115.2	.9	do	15,170	1969	3,600	Do.
National Park		18.6	.85	Kerosene	13,650	1969	3,600	Do.
Philadelphia Electric Co.:								
Plymouth Meeting	IC	6	.8	Oil	10,100	1959	900	Automatic.
Barbados Unit 6	GT	22	.85	Gas	15,800	1961	3,600	Do.
Barbados Unit 7	GT	23	.85	do	15,300	1967	3,600	Do.
Cromby	IC	2.75	.80	Oil	10,450	1967	900	Do.
Delaware	IC	2.75	.80	do	10,450	1967	900	Do.
Eddystone	GT	18.6	.85	do	12,600	1967	3,600	Do.
Richmond	IC	2.75	.80	do	10,450	1967	900	Do.
Southwark	IC	2.75	.80	do	10,450	1967	900	Do.

See footnotes at end of table.

	Type	Nameplate rating MW	Nameplate rating P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
				STUDY AREA C—Continued				
Philadelphia Electric Co.—Continued								
Chester	IC	2.75	.80	Oil	10,450	1967	900	Automatic.
Southwark	GT	18.6	.85	do	12,600	1967	3,600	Do.
Schuykill	IC	2.75	.80	do	10,450	1967	900	Do.
Barbados	IC	2.75	.80	do	10,450	1967	900	Do.
Southwark	GT	18.6	.85	do	12,600	1967	3,600	Do.
Southwark	GT	18.6	.80	do	12,600	1967	3,600	Do.
Eddystone	GT	18.6	.80	do	12,600	1967	3,600	Do.
Chester	GT	55.8	.80	do	12,600	1969	3,600	Do.
Delaware	GT	74.4	.80	do	12,600	1969	3,600	Do.
Peach Bottom	IC	1.0	.80	do	11,800	1966	720	Do.
Southwark (13 Unassigned GT's in 1971, about 20 Mw each).								
Accomack-North Hampton Electric Coop.:								
Parksley	IC	0.875	.8	No 2 oil	N.A.	1949	N.A.	N.A.
	IC	0.300	.8	do	N.A.	1936	N.A.	Do.
	IC	0.728	.8	do	N.A.	1948	N.A.	Do.
	IC	0.250	.8	do	N.A.	1942	N.A.	Do.
	IC	0.250	.8	do	N.A.	1942	N.A.	Do.
Easton Utilities Commission:								
Easton	IC	0.30	.8	Oil/NG	10,000	1927	225	Manual.
	IC	0.52	.8	do	10,000	1929	225	Do.
	IC	0.70	.8	do	10,000	1936	300	Do.
	IC	0.70	.8	do	10,000	1941	257	Do.
	IC	1.25	.8	Oil/NG	10,000	1946	277	Manual.
	IC	1.40	.8	do	10,000	1950	277	Do.
	IC	2.50	.8	do	10,000	1954	277	Do.
	IC	2.50	.8	do	10,000	1956	277	Do.
	IC	3.00	.8	do	10,000	1961	514	Do.
	IC	3.50	.8	do	10,000	1966	360	Do.
Berlin Mun.:								
Berlin	IC	0.200	.8	Oil	N.A.	1937	N.A.	Do.
	IC	0.300	.8	do	N.A.	1939	N.A.	Do.
	IC	0.556	.8	do	N.A.	1946	N.A.	Do.
	IC	0.556	.8	do	N.A.	1950	N.A.	Do.
	IC	1.400	.8	do	N.A.	1956	N.A.	Do.
	IC	1.136	.8	do	N.A.	1961	N.A.	Do.
Centreville Electric Plant:								
Centreville	IC	0.30	.8	do	N.A.	1931	N.A.	Do.
	IC	0.70	.8	do	N.A.	1938	N.A.	Do.
	IC	1.00	.8	do	N.A.	1946	N.A.	Do.
	IC	1.15	.8	do	N.A.	1950	N.A.	Do.
Girard Borough Light Distribution:								
Girard	IC	0.200	.8	do	N.A.	1937	N.A.	Do.
	IC	0.200	.8	do	N.A.	1937	N.A.	Do.
	IC	1.132	.8	do	N.A.	1956	N.A.	Do.
	IC	0.200	.8	do	N.A.	1941	N.A.	Do.
	IC	0.200	.8	do	N.A.	1947	N.A.	Do.
	IC	0.400	.8	do	N.A.	1948	N.A.	Do.
	IC	0.675	.8	do	N.A.	1952	N.A.	Do.
	IC	1.132	.8	do	N.A.	1962	N.A.	Do.

	Type	Nameplate rating MW	P.F.	Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
STUDY AREA C—Continued								
Hatfield Borough Electric Light Plant:								
Hatfield	IC	0.105	.7	Oil	N.A.	1931	N.A.	Manual.
	IC	0.105	.7	.....do	N.A.	1931	N.A.	Do.
	IC	0.300	.7	.....do	N.A.	1945	N.A.	Do.
	IC	0.300	.7	.....do	N.A.	1950	N.A.	Do.
	IC	0.675	.7	.....do	N.A.	1956	N.A.	Do.
	IC	1.200	.7	.....do	N.A.	1965	N.A.	Do.
Landsdale Municipal Power Plant:								
Landsdale	GT	11.25	.8	Oil/NG	11,250	1963	3,600	Automatic.
Lewes Board of Public Works:								
Lewes	IC	0.382	.8	Oil	N.A.	1929	N.A.	Manual.
	IC	0.476	.8	.....do	N.A.	1937	N.A.	Do.
	IC	0.600	.8	.....do	N.A.	1941	N.A.	Do.
	IC	0.600	.8	.....do	N.A.	1942	N.A.	Do.
	IC	0.690	.8	.....do	N.A.	1953	N.A.	Do.
	IC	0.690	.8	.....do	N.A.	1953	N.A.	Do.
Pemberton Electric Department:								
Pemberton	IC	0.072	.8	.....do	N.A.	1927	N.A.	Do.
	IC	0.200	.8	.....do	N.A.	1951	N.A.	Do.
	IC	0.138	.8	.....do	N.A.	1938	N.A.	Do.
	IC	0.200	.8	.....do	N.A.	1951	N.A.	Do.
	IC	0.200	.8	.....do	N.A.	1951	N.A.	Do.
Quakertown Electric Light Department:								
Quakertown	IC	1.10	.8	Oil/NG	10,069	1954	600	Semiauto.
	IC	1.05	.8	.....do	9,362	1957	600	Do.
	IC	1.75	.8	.....do	8,750	1960	450	Do.
South River Board of Public Works:								
Whitehead Ave	IC	0.250	.6	Oil	24,278	1922	164	Manual.
	IC	0.475	.8	.....do	18,926	1923	164	Do.
	IC	0.800	.8	.....do	15,977	1928	164	Do.
	IC	1.050	.8	.....do	12,318	1941	225	Do.
	IC	1.100	.8	.....do	10,644	1955	625	Do.
	IC	1.100	.8	.....do	10,624	1956	625	Do.
William Street	IC	1.420	.8	.....do	10,714	1961	327	Do.
Seaford Light and Power Dept.:								
Seaford	IC	1.36	.8	.....do	N.A.	1958	N.A.	Do.
	IC	1.36	.8	.....do	N.A.	1954	N.A.	Do.
	IC	1.136	.8	.....do	N.A.	1951	N.A.	Do.
	IC	0.606	.8	.....do	N.A.	1940	N.A.	Do.
	IC	0.840	.8	.....do	N.A.	1947	N.A.	Do.
	IC	2.000	.8	.....do	N.A.	1962	N.A.	Do.
Weatherly Borough Light and Power Plt.:								
Weatherly	IC	1.0	.8	.....do	N.A.	1951	N.A.	Do.
	IC	1.0	.8	.....do	N.A.	1957	N.A.	Do.
Pennsylvania Power and Light Co.:								
Allentown	GT	64.0	.85	No. 2 oil	13,980	1967	3,600	Remote.
Harrisburg	GT	64.0	.85	.....do	13,980	1967	3,600	Do.
Harwood	GT	32.0	.85	.....do	13,980	1967	3,600	Do.
Williamsport	GT	32.0	.85	.....do	13,980	1967	3,600	Do.
Georgetown	CT	32.0	.85	.....do	13,980	1967	3,600	Do.
Brunner Isl	IC	8.25	.85	.....do	9,120	1967	900	Do.
Sunbury	IC	5.50	.85	.....do	9,120	1967	900	Do.
Martins Creek No. 3	IC	2.75	.80	.....do	9,120	1967	900	Do.
Martins Creek No. 4	IC	2.75	.80	.....do	9,120	1967	900	Do.

	Type	Nameplate rating		Fuel type	Fuel consumption at full load (BTU/KWH)	In-service date	Shaft speed (RPM)	Method of operation
		MW	P.F.					
STUDY AREA C—Continued								
Pennsylvania Power and Light Co.—Continued								
West Shore	GT	37.2	.85	No. 2 Oil	11,400	1969	3,600	Remote.
Lock Haven No. 1	GT	18.6	.85	do	11,400	1969	3,600	Do.
Fishback	GT	37.2	.85	do	11,400	1969	3,600	Do.
Suburban	GT	31.3	.90	Jet A	12,700	1968	3,600	Do.
Potomac Electric Power Co.:								
Dickerson	GT	16.15	.85	No. 2	14,000	1967	3,600	Peaking.
Chalk Point	GT	16.15	.85	do	14,000	1967	3,600	Do.
Buzzard	GT	268	.85	do	16,000	1968	3,600	Do.
Unassigned		134	.85	Gas		1969	3,600	Do.
Atlantic City Electric Co.:								
Deepwater	GT	18.6	.85	JP	12,950	1967	3,600	Remote/ Local.
Missouri Avenue	GT	55.8	.85	do	12,950	1969	3,600	Do.
B. L. England	IC	[1]8	.80	No. 2 oil	10,250	1961	900	Do.
Missouri Ave	IC	[1]2	.80	do	10,250	1963	900	Do.
Missouri Ave	IC	0.5	.80	do	10,250	1958	720	Local.
Delmarva Power and Light Co.:								
Delaware City	GT	18.9	.85	do	12,350	1968	3,600	Semiauto.
Indian River	GT	18.9	.85	do	12,200	1967	3,600	Do.
Vienna	GT	18.9	.85	do	12,200	1968	3,600	Do.
Crisfield	IC	11	.80	do	10,450	1968	900	Automatic.
South Madison St	GT	11.5	.85	Oil/NG	17,422	1967	3,600	Semiauto.
	IC	0.5	.8	Oil	N.A.	1964	720	Manual.
Chincoteague	IC	2.0	.8	do	10,250	1964	900	Do.
Tasley	IC	0.320	.8	do	12,000	1929	257	Do.
	IC	0.489	.8	do	12,000	1937	257	Do.
	IC	0.565	.8	do	12,000	1965	257	Do.
Cape Charles	IC	1.125	.8	do	12,000	1947	277	Do.
	IC	1.000	.8	do	12,000	1948	240	Do.
Edge Moor	GT	15.000	.85	Gas	15,259	1963	3,600	Semiauto.
West	GT	20.000	.85	do	14,250	1964	3,600	Do.
Kent	GT	13.500	.85	Oil	15,450	1964	3,600	Automatic.
Bayview	IC	2.000	.8	do	10,250	1964	900	Do.
	IC	2.000	.8	do	10,250	1964	900	Do.
	IC	2.000	.8	do	10,250	1964	900	Do.
	IC	2.000	.8	do	10,250	1964	900	Do.
	IC	2.000	.8	do	10,250	1964	900	Do.
General Public Utilities:								
Shawville	IC	6.0	.8	Diesel	10,547	1966	900	Semiauto.
Portland	GT	16	.85	No. 2 oil		1967	3,600	Do.
Titus	GT	16	.85	do	10,547	1967	3,600	Do.
Benton	IC	2	.80	Diesel	10,547	1960	900	
Benton	IC	2	.80	do	10,547	1960	900	
Baltimore Gas and Electric Co.:								
Crane	GT	16	.85	No. 2 oil	14,400	1967	3,600	Peaking.
Wagner	GT	16	.85	do	14,400	1967	3,600	Do.
Westport	GT	121.5	.90	N.G	15,330	1969	3,600	Do.

[1] House units.

[2] Natural gas burning units limited to 27,000 CFH with a special No. 1 diesel oil burned as necessary for extra load requirements.

[3] Under Construction.

[4] Turbine speed. Generator speed is 3600.

NOTE.—N.A.—Data not available.

Steam-Electric Peaking Units

	Rating: KW	Rating: P.F.	Fuel: Type	Fuel: K BTU/LB	Fuel consumption (BTU/KWH)	Emergency capacity (MW)	Method of modifying operation
			Units integral with baseload				
Niagara Mohawk Co.:							
Albany Unit 1........	100	0. 80	Coal.......	12. 8	9, 564	7	Close certain extraction heater valves and increase steam flow into turbines by raising boiler pressures slightly above normal.
Albany Unit 2........	100	. 80	...do.......	12. 8	9, 564	6	
Albany Unit 3........	100	. 80	...do.......	12. 8	9, 564	7	
Albany Unit 4........	100	. 80	...do.......	12. 8	9, 564	9	
Dunkirk Unit 1.......	96	. 80	...do.......	13. 5	9, 847	7	Do.
Dunkirk Unit 2.......	96	. 80	...do.......	13. 5	9, 847	9	
Dunkirk Unit 3.......	218	. 85	...do.......	13. 5	9, 382	18	
Dunkirk Unit 4.......	218	. 85	...do.......	13. 5	9, 085	18	
Oswego Unit 1........	92	. 80	...do.......	13. 5	11, 595	5	Do.
Oswego Unit 2........	92	. 80	...do.......	13. 5	11, 595	5	
Oswego Unit 3........	92	. 80	...do.......	13. 5	11, 374	6	
Oswego Unit 4........	100	. 80	...do.......	13. 5	9, 975	7	
Huntley Unit 63......	92	. 80	...do.......	13. 5	11, 861	5	Do.
Huntley Unit 64......	100	. 80	...do.......	13. 4	11, 008	5	
Huntley Unit 65......	100	. 80	...do.......	13. 5	9, 609	7	
Huntley Unit 66......	100	. 80	...do.......	13. 5	9, 958	7	
Huntley Unit 67......	218	. 85	...do.......	13. 5	9, 366	20	
Huntley Unit 68......	218	. 85	...do.......	13. 5	9, 168	20	
Long Island Lighting Co.:							
Northport Unit 1......	375	. 90	No. 6 oil...	18. 1	9, 300	[1] 20	Remove top feedwater heater from service.
Northport Unit 2......	375	. 90	...do.......	18. 1	9, 300	20	

	Rating: MW	Rating: P.F.	Fuel: Type	Fuel: K BTU/LB	Fuel consumption (BTU/KWH)	Installed cost ($/KW)	Method of reducing capital cost
			Units designed specifically for peaking				
Potomac Electric Power Co.: Benning Unit 15 (in service).	289	0. 90	No. 6 oil...	18. 6	10, 394	66	Eliminate regenerative or tubular air heater. Reduction of steam temperature.
New England Electric System: Salem Harbor No. 4 (Scheduled for 1972–73 installation).	450	N.A.	...do.......	18. 4	10, 500	117	Eliminate rotating type air pre-heaters conservative initial steam conditions for cyclic operation, turbine designed for cyclic operation.
Northeast Utilities: Montville No. 6 (Scheduled for 1971–72 installation).	400	. 90	Oil........	17. 2	10, 700	100	Design for cycling operation no air preheater, only 2–3 feed water heaters, extended clearance on turbogenerator unit.

[1] Approximate capacity.

Steam-Electric Plants 50 Megawatts and Over

Name of Plant and Location	Installed capacity—Dec. 31, 1967 (KW name-plate rating)
STUDY AREA A	
Bangor Hydro-Electric Co.:	
Graham Station—Veazie, Me	57,450
Central Maine Power Co.:	
Mason—Wiscasset, Me	146,500
William F. Wyman—Yarmouth, Me	213,636
Boston Edison Co.:	
"L" Street—South Boston, Mass	168,750
Edgar—North Weymouth, Mass	457,860
Mystic—Everett, Mass	618,750
New Boston—South Boston, Mass	717,740
New England Gas & Electric Association:	
Cannon Street—New Bedford, Mass	130,500
Kendall Station—Cambridge, Mass	67,450
Eastern Utilities Associates:	
Montaup—Somerset, Mass	329,000
Fitchburg Gas and Electric Co.:	
Fitchburg—Fitchburg, Mass	61,385
Connecticut Yankee Atomic Power Company:	
East Haddam—East Haddam, Conn	[2] 600,300
New England Power System:	
Brayton Point—Somerset, Mass	482,000
Salem—Salem, Mass	319,938
Manchester Street—Providence, R.I	132,000
South Street—Providence, R.I	188,625
Lynnway—Lynn, Mass	56,500
Northeast Utilities System:	
Devon—Devon, Conn	479,000
Montville—Montville, Conn	176,000
Norwalk Harbor—Norwalk, Conn	326,400
Middletown—Middletown, Conn	421,996
South Meadow—Hartford, Conn	216,750
Stamford—Stamford, Conn	52,500
Mt. Tom—Holyoke, Mass	136,000
West Springfield—West Springfield, Mass	209,636
Yankee Atomic Electric Company:	
Rowe—Rowe, Mass	[2] 185,000
Public Service Company of N.H.:	
Merrimack—Bow, N.H	113,636
Schiller—Portsmouth, N.H	193,750
The United Illuminating Co.:	
English Station—New Haven, Conn	146,250
Steel Point Station—Bridgeport, Conn	155,500
Bridgeport Harbor Station, Bridgeport, Conn	261,042
STUDY AREA B	
City of Jamestown:	
Samuel A. Carlson—Jamestown, N.Y	57,500
New York State Electric & Gas Corp.:	
Goudey—Binghamton, N.Y	145,750
Greenidge—Dresden, N.Y	160,000

Steam-Electric Plants 50 Megawatts and Over—Continued

Name of Plant and Location	Installed capacity—Dec. 31, 1967 (KW name-plate rating)
STUDY AREA B—Continued	
New York State Electric and Gas Corp.—Continued	
Hickling—E. Corning, N.Y	70,000
Jennison—Bainbridge, N.Y	60,000
Milliken—Ludlowville, N.Y	270,000
Niagara Mohawk Power Corp.:	
Albany—Albany, N.Y	400,000
Dunkirk—Dunkirk, N.Y	628,000
Huntley—Buffalo, N.Y	828,000
Oswego—Oswego, N.Y	376,000
Rochester Gas & Electric Corp.:	
Station No. 3 (Beebe)—Rochester, N.Y	206,200
Station No. 7 (Russell)—Greece, N.Y	252,600
Central Hudson Gas & Electric Corp.:	
Danskammer—Roseton, N.Y	531,910
Consolidated Edison Company of New York:	
Waterside—New York, N.Y	712,250
East River—New York, N.Y	833,652
Hell Gate—Bronx, N.Y	611,250
Sherman Creek—New York, N.Y	216,500
Astoria—Queens, N.Y	1,550,600
Hudson Avenue—Brooklyn, N.Y	845,000
Arthur Kill—Staten Island, N.Y	376,200
Ravenswood—Queens, N.Y	1,827,700
Kent Avenue—Brooklyn, N.Y	107,500
59th Street—New York, N.Y	149,500
74th Street—New York, N.Y	269,000
Indian Point—Buchanan, N.Y	275,000
Long Island Lighting Co.:	
Port Jefferson—Port Jefferson, N.Y	467,000
Glenwood—Glenwood Landing, N.Y	397,272
Edward F. Barrett—Island Park, N.Y	375,000
Far Rockaway—Far Rockaway, N.Y	133,636
Northport—Northport, N.Y	387,090
Orange & Rockland Utilities:	
Lovett—Tomkins Cove, N.Y	294,520
STUDY AREA C	
Atlantic City Electric Co.:	
Missouri Ave.—Atlantic City, N.J	50,000
Deepwater—Deepwater, N.J	308,300
B. L. England—Bossley's Point, N.J	299,200
Delmarva Power & Light Co.:	
Edge Moor—Edge Moor, Del	389,800
Delaware City—Delaware City, Del.	130,000
Indian River—Millsboro, Del	163,200
Vienna—Vienna, Md	94,680
Baltimore Gas & Electric Co.:	
Westport—Baltimore, Md	311,500
Gould Street—Baltimore, Md	173,400
Riverside—Near Baltimore, Md	333,500

Steam-Electric Plants 50 Megawatts and Over—Continued

Name of Plant and Location	Installed capacity—Dec. 31, 1967 (KW name-plate rating)
STUDY AREA C—Continued	
Baltimore Gas and Electric Co.—Continued	
Herbert A. Wagner—Anne Arundel Co., Md	627, 800
Charles P. Crane—Baltimore, Md	399, 840
Sparrows Point (Bethlehem Steel Co.)—Baltimore, Md	158, 500
General Public Utilities Corp.:	
Jersey Central Power & Light Co.:	
Sayreville—Sayreville, N.J	346, 750
Werner—South Amboy, N.J	116, 250
Metropolitan Edison Co.:	
Portland—Portland, Pa	426, 700
Titus—Reading, Pa	225, 000
Crawford—Middletown, Pa	116, 750
Eyler—Reading, Pa	84, 000
New Jersey Power & Light Co.:	
Gilbert—Holland, N.J	126, 100
Pennsylvania Electric Co.:	
Shawville—Shawville, Pa	640, 000
Seward—Seward, Pa	268, 250
Warren—Warren, Pa	73, 442
Front—Erie, Pa	118, 750
Keystone—Indiana, Pa	[1] 936, 000
Pennsylvania Power & Light Co.:	
Brunner Island—York Haven, Pa	768, 330
Sunbury—Shamokin Dam, Pa	409, 780
Martins Creek—Martins Creek, Pa	312, 500
Stanton—Harding, Pa	146, 000
Hauto—Hauto, Pa	106, 000
Holtwood—Holtwood, Pa	105, 000
Philadelphia Electric Co.:	
Barbadoes—Norristown, Pa	180, 000
Chester—Chester, Pa	256, 000
Cromby—Cromby, Pa	417, 500

Steam-Electric Plants 50 Megawatts and Over—Continued

Name of Plant and Location	Installed capacity—Dec. 31, 1967 (KW name-plate rating)
STUDY AREA C—Continued	
Philadelphia Electric Co.—Continued	
Delaware—Philadelphia, Pa	499, 250
Eddystone—Eddystone, Pa	707, 200
Richmond—Philadelphia, Pa	474, 750
Schuykill—Philadelphia, Pa	325, 400
Southwark—Philadelphia, Pa	345, 000
Peach Bottom—Peach Bottom, Pa	[2] 46, 000
Vineland, City of:	
Vineland	52, 500
Public Service Electric & Gas Co.:	
Bergen—Ridgefield, N.J	650, 432
Burlington—Burlington, N.J	490, 500
Essex—Newark, N.J	320, 500
Hudson—Jersey City, N.J	454, 780
Kearny A—Kearny, N.J	304, 500
Kearny B—Kearny, N.J	284, 550
Linden—Linden, N.J	519, 444
Marion—Jersey City, N.J	125, 000
Mercer—Hamilton Twp., N.J	652, 800
Sewaren—Sewaren, N.J	811, 210
United Gas Improvement Co.:	
Hunlock—Hunlock Creek, Pa.	93, 000
Potomac Electric Power Co.:	
Benning—Washington, D.C	263, 750
Buzzard Point—Washington, D.C	270, 000
Potomac River—Alexandria, Va	514, 750
Dickerson—Dickerson, Md	586, 500
Chalk Point—Brandywine Md	727, 600

[1] Operated by Pennsylvania Electric for Jersey Central Power and Light Company, Atlantic City Electric Company, Delamarva Power and Light Company, Philadelphia Electric Company, Pennsylvania Power and Light Company, Public Service Electric and Gas Company, and Baltimore Gas and Electric Company.

[2] Nuclear Plant.

APPENDIX B

NORTHEAST POWER COORDINATING COUNCIL (NPCC)

Basic Criteria for Design and Operation of Interconnected Power Systems

(As adopted by the members of Northeast Power Coordinating Council, September 20, 1967)

1. Introduction

The purpose of the Northeast Power Coordinating Council is to improve the reliability and efficiency of the interconnected power systems of its members through improved coordination in system design and operating procedures.

One of the steps in reaching this objective is the development of criteria that will be used in the design and operation of the major interconnected transmission systems.

It is recognized that more rigid criteria will be applied in some segments of the Council area because of local considerations. It is also recognized that the basic criteria are not necessarily applicable to those elements of the individual members' systems that are not a part of the interconnected transmission network.

The criteria are applicable either to the areas (New York, Ontario, or New England), or to the entire Council interconnection in its relations with neighboring "pools."

An interconnected power system should be designed and operated at a level of reliability such that the loss of a major portion of the system would not result from reasonably foreseeable contingencies. In determining this reliability, it would be desirable to give consideration to all combinations of contingencies occurring more frequently than once in some stipulated number of years. However, sufficient data and techniques are not available at the present time to define all the contingencies that could occur or to assess and rank their probability of occurrence. Therefore, it is proposed that the interconnected systems be designed and operated to meet certain specific contingencies. Loss of small portions of the system (such as radial portions) may be tolerated, provided that these do not jeopardize the integrity of the overall interconnected system. Definition of several terms used in the following paragraphs is appended.

The following criteria for design and operation of interconnected power systems define area generation and transmission requirements. In addition, criteria for determining inter-area transmission capabilities are defined.

Two categories of inter-area power transfer are to be considered where applicable:

a. Normal (contractual plus economy)

b. Emergency (contractual plus emergency)

Design studies will assume applicable contractual transfers and the most severe expected load and generation conditions. Operating limit studies will be based on the particular load and generation pattern expected to exist for the period under study. All reclosing facilities will be assumed in service unless it is known that such facilities have been rendered inoperative.

2. Generating Capacity

Generating capacity will be installed and located in such a manner that after due allowance for required maintenance and expected forced outages, each area's generating supply will equal or exceed area load at least 99.9615 percent of the time. This is equivalent to a "loss-of-load probability of one day in ten years".

3. Area Transmission Requirements

The system should be designed with sufficient transmission capacity within each area to serve area loads under the following conditions.

3.1 Stability Conditions

Stability of the interconnected systems shall be maintained during and after the most severe of the conditions stated in below a, b, c and d. Also, the system must be

adequate for testing of the faulted element by manual reclosing after the outage and before adjusting the generation. These requirements will also apply after one generator unit, circuit or transformer has already been lost, assuming that the system generation and power flows are adjusted between outages by use of operating reserve.

a. A permanent three phase fault on any element with due regard to reclosing facilities.
b. A permanent phase to ground fault on the same phase of both circuits on a double circuit tower with due regard to reclosing facilities.
c. A permanent phase to ground fault on any element with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to breaker, relay system or signal channel malfunction.
d. Loss of any element, including a generator.

3.2 Steady State Conditions

a. Voltages, line and equipment loading shall be within normal limits for predisturbance conditions.
b. Voltages, line and equipment loading shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 3.1.

For operating purposes, with transmission facilities out of service, transmission line loadings will be adjusted so that the criteria are met unless an emergency condition exists.

4. Inter-Area Transfer Capability

Transfers of power from one area to another should be considered in the design of inter-area transmission and internal area facilities.

Operating limits are required for normal transfers and transfers during emergencies. These limits will be based on the facilities in service at the time of the transfer. In determining the emergency transfer limits, it is assumed that a less conservative margin is justified.

Transfer limits shall be determined under the following conditions:

4.1 Normal Transfers

4.1.1 Stability Conditions

Stability of the interconnected systems shall be maintained during and after the most severe of the conditions stated in a, b, c and d. Also, the system must be adequate for testing of the faulted element by manual reclosing after the outage and before adjusting the generation.

a. A permanent three phase fault on any element with due regard to reclosing facilities.
b. A permanent phase to ground fault on the same phase of both circuits on a double circuit tower with due regard to reclosing facilities.
c. A permanent phase to ground fault on any element with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to breaker, relay system or signal channel malfunction.
d. Loss of any element, including a generator.

4.1.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within normal limits.
b. Voltages, line and equipment loadings shall be within applicable emergency limits for the system load and generation conditions that exist following the disturbance specified in 4.1.1.

4.2 Emergency Tranfers

4.2.1 Stability Conditions

Stability of the interconnected systems shall be maintained following the loss of any generating unit or during and after a permanent two phase to ground fault on any element with due regard to reclosing facilities. If such reclosing facilities are inoperative, system conditions may be adjusted before the faulted element is tested.

4.2.2 Steady State Conditions

a. For the facilities in service during the transfer, voltages, line and equipment loadings shall be within applicable emergency limits.

b. Voltages, line and equipment loadings shall be within applicable emergency limits following the disturbance in 4.2.1.

5. Possible But Improbable Contingencies

Studies will be conducted to determine the effect of the following contingencies on system performance and plans will be developed to minimize the spread of any interruption that might result.

a. Loss of the entire capability of a generating station.

b. Loss of all lines emanating from a generating station, switching station or substation.

c. Loss of all circuits on a common right-of way.

d. A permanent three phase fault with delayed clearing and with due regard to reclosing facilities. This delayed clearing could be due to breaker, relay system or signal channel malfunction.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

List of Definitions

1. Area

An area is defined as either New England, New York or Ontario.

2. Emergency

An emergency is assumed to exist in an area if in that area firm load must be dropped because additional power is unavailable.

3. Applicable Emergency Limits

These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Short time emergency limits are those which can be utilized for at least five minutes.

The limiting condition for voltages should recognize that voltages at key locations should not drop below that required for suitable system stability performance, and should not adversely affect the operation of the interconnected systems.

The limiting condition for equipment loadings should be such that cascading will not occur due to operation of protective devices or the failure of facilities.

4. Operating Reserve

Operating reserve is that amount of additional generation which any particular area has available within a specified number of minutes.

5. "With Due Regard To Reclosing Facilities"

This is intended to mean that recognition will be given to the type of reclosing, i.e., manual or automatic, and the kind of protective schemes insofar as time is concerned.

Northeast Power Coordinating Council Procedure in a Major Emergency

Recommended by the Operating Procedure Coordinating Committee on 8–25–66, adopted by unanimous consent of the membership as the official position of the NPCC and as revised to reflect the Disposition of the Recommendations Contained in the Stone & Webster Northeast Interconnection Study unanimously approved by the Council membership 5–24–67.

Introduction

This procedure outlines a plan of operations to be followed in the event of a major emergency such as unusually low frequency, equipment overload, or low voltage, which might seriously affect the operation of consumers' or electrical utilities' equipment. The objectives of the plan are:

1. To minimize the effect on customer service.
2. To restore the balance between load and generation in the shortest practical time.
3. To minimize the risk of damage to transmission and generating facilities, to distribution equipment and to customers' utilization equipment.

The plan of operation is intended to indicate the results that should be attained but does not indicate the method to be used to obtain these results. The basic system designs and the methods of control vary widely among the systems. These are influenced by the character of the load supplied, the geography of the area, the extent of underground construction and many other factors. The methods to be used in implementing this procedure in detail in each area will not necessarily be uniform but must be coordinated.

Definitions

Load Relief__	Load reduction accomplished by reducing voltage or by load shedding or both.
Automatic Load Relief.	Load reduction accomplished without manual intervention by reducing voltage or by load shedding or both.
Load Shedding.	Interruption of customer load.
Dispatchers __	The terms dispatcher and system operator have the same meaning.
Area _______	As the situation requires, may mean a part of a system, or more than a single system.

Principles

The plan of operation derives from the following basic principles:

1. Tie lines, including internal transmission circuits, should not be opened deliberately except to prevent sustained interruption to customers' service or to prevent damage either to such tie lines or to equipment due to overloads, extreme voltages, or extreme frequencies.
2. A sustained frequency excursion of $\pm .2$ cycles is an indication of major load-generation unbalance. It is important for the trouble area to provide load-generation balance at once to restore frequency so that any separated areas may be reparalleled as soon as possible to protect against further troubles or internal separations.
3. Any general rule for load relief based on frequency alone risks undesirable overloading or tripping of tie lines or internal transmission circuits. If frequency is dropping rapidly, these risks are preferred to the risk of widespread shutdowns.
4. At some low frequency, the ability of generators to maintain output is endangered. Although some machines will operate safely below 58.5 cycles, for the sake of uniformity the value of 58.5 cycles has been selected for the last step in the following procedure. It is recognized, however, that some machines may be in danger above 58.5 cycles. If a machine is tripped above 58.5 cycles, equivalent load relief must be provided.

Requirements

In order to follow the recommended plan of operation effectively, each system should meet the following requirements:

1. Accurate and reliable metering of tie line loadings and system frequency should be available at each dispatch center.
2. Reliable and immediately available communication channels should exist between the dispatchers of adjacent power systems.
3. Each dispatcher should know the permissible emergency loading of each of his tie lines and transmission circuits which can be utilized for at least 5 minutes. The settings of the relays on the tie lines must exceed this value.
4. Each system must provide a means to relieve a minimum of 25% of its system load automatically to protect against low frequency conditions and a minimum of 50% of its system load manually to protect against low voltage and overload conditions. The automatic portion, if also controlled by manual means, may be included as part of the 50% manual relief.
5. All automatic load frequency controls will be removed from service before the frequency has declined to 59.5 cycles.

Load Relief Procedure

A. Low Frequency Condition

1. Operator Action

When the generation-deficient area is clearly identifiable, when the frequency decline is slow enough to permit communication among various system operators, and when adequate consideration can be given to the amount of assistance which can be delivered to the deficient

area by all power systems, the following procedures will apply.

The deficient system will initiate immediate action to correct load-generation unbalance.

a. 59.5 to 59.0 cps—All systems should have achieved a 10% load relief if the loadings on tie lines permit.

b. 59.0 to 58.5 cps—All systems should have achieved an additional 15% load relief if the loadings on tie lines permit.

c. 58.5 cps—If frequency is still declining, all systems shall take such steps as are necessary, including separating units to preserve generation, minimize damage and service interruptions.

When the generation-deficient area is not clearly identifiable and when the frequency decline is so rapid as to preclude analysis and communication among various system operators, the above procedure will apply without regard to tie line loadings.

2. Automatic Action

In addition to above "Operator Action", automatic facilities will be provided to achieve the results of 1 a. and 1 b. above.

B. Tie Line Overload Condition

1. Establish communication with system operator of system producing overload.
2. Attempt to have overload reduced from source; if, after a reasonable time based on overload, improvement is not made, open those ties necessary to prevent damage to equipment.

C. Low Voltage Condition

1. Establish communication with part of system causing the low voltage.
2. Attempt to have voltage level raised at source.
3. Assist in raising voltage if possible.
4. If, after a reasonable time based on voltage level, improvement is not made, separate the affected portion of the system to prevent damage to equipment.

Restoration Procedure

In the event that an area becomes isolated and after the frequency decline has been arrested:

1. Restore frequency to 60 cycles.
2. Establish communication with system operators of adjacent systems.
3. Synchronize with adjacent systems.
4. Coordinate restoration of any load previously shed.

It is permissible to restore load concurrent with the performance of steps (2) and (3) provided frequency is maintained at 60 cycles, other system conditions permit and synchronization with adjacent systems is not delayed as a result of such action.

APPENDIX C

MIDDLE ATLANTIC AREA COORDINATION GROUP (MAAC)

Area Coordination Committee Procedures

(Approved by the Executive Board on July 18, 1968)

The responsibilities of the Area Coordination Committee as set forth in Article 3, Section 3.4(b) of the MAAC Agreement are to be carried out in accordance with the procedures outlined herein.

In discharging its duties the Area Coordination Committee shall issue an annual report to the Executive Board summarizing the proposed plans of the signatories and evaluating their adherence to the approved reliability standards. The plans shall be the firm intentions of the signatories for the number of years required to install the various types of facilities and preliminary beyond those times through ten years. Also the Area Coordination Committe will review quarterly any changes from previous plans to assure continued reliability of the MAAC system with the facilities planned.

These procedures shall be put into effect immediately after approval by the Executive Board. The MAAC system shall meet the approved standards by June 1, 1972.

A. Specific Plans

These shall include facilities for the number of years necessary to meet the then current estimated lead time requirements.

1. Each signatory shall plans its own generation and bulk power transmission system within the framework of policies established by the Executive Board.
2. Each signatory shall report to the Chairman of the Executive Board its plans for addition, modification or removal of generating and bulk transmission facilities. Such reports shall be submitted before the commitments for any such additions, modifications or removals of facilities are undertaken.
3. The Chairman of the Executive Board shall furnish all members of the Executive Board copies of these reports and request that the Area Coordination Committee review the same.
4. The Area Coordination Committee shall then:
   - (a) In conjunction with each signatory, review the plans submitted and request any additional studies or data which it considers to be necessary.
   - (b) Evaluate the plan and resulting system conditions to establish conformity with MAAC reliability principles and standards and coordinated area long-range plans.
   - (c) Should additional studies be required in order to establish conformity with the above, the plans shall be submitted to other signatories or coordinated planning group(s) of the signatories.
   - (d) The Area Coordination Committee's evaluation of plans, together with any minority reports, shall be transmitted to the Executive Board within three months after receipt of the plans.

B. Installed Generating Capacity Requirements

1. Signatories shall submit plans for generating capacity additions and load forecasts for ten years to the Area Coordination Committee every year for determination of probability of loss of load of the MAAC system.
2. The Area Coordination Committee shall:
   - (a) In conjunction with each signatory, review the plans submitted and request any additional studies or data which it considers to be necessary.
   - (b) Evaluate the plan to establish conformity with MAAC reliability princi-

ples and standards, and compatibility with plans of other signatories.

(c) The MAAC system load and capacity forecast shall be submitted to the Executive Board by May 1 of each year.

C. Megavar Capacity Requirements

1. Signatories (or coordinated planning groups of signatories) shall submit five-year plans for Mvar load and capacity forecasts by areas to the Area Coordination Committee every year.
2. The Area Coordination Committee shall:
   (a) Submit the plans to coordinated groups of the signatories for evaluation and recommendation on an area basis.
   (b) Evaluate the recommendations from (a) above for conformity with MAAC reliability principles and standards, and compatibility with plans of other signatories.
   (c) The MAAC system Mvar load and capacity forecast shall be submitted to the Executive Board by May 1 of each year.

D. Long-Range Plans

1. Signatories (or coordinated planning groups of signatories) shall submit tentative long-range plans (at least 10 years) to the Area Coordination Committee by October 1 of each year.
2. The Area Coordination Committee shall:
   (a) In conjunction with each signatory, review the plans submitted and request any additional studies or data which it considers to be necessary.
   (b) Evaluate the plans to explore compatibility with those of other signatories.
   (c) The MAAC system coordinated long-range plan shall be transmitted to the Executive Board within six months after receipt of the individual plans.

E. General

The Area Coordination Committee shall report to the Executive Board all apparent system inadequacies that may come to its attention with recommendations for corrective action.

MID-ATLANTIC AREA COORDINATION GROUP (MAAC) RELIABILITY PRINCIPLES AND STANDARDS FOR PLANNING BULK ELECTRIC SUPPLY SYSTEM OF MAAC GROUP

(As adopted on July 18, 1968, by the Executive Board constituted under MAAC Agreement, dated December 26, 1967.)

Principles

The bulk electric supply system shall be planned and constructed in such manner that it can be operated so the more probable contingencies can be sustained with no loss of load. Less-probable contingencies will be examined to determine their effect on system performance. These standards apply only to those facilities which affect reliability of the MAAC system and not to facilities affecting the reliability of supply only to local system loads. Automatic load relief shall be provided to minimize the probability of the total shutdown of an area which becomes isolated by multiple contingencies, thereby facilitating rapid restoration of the interconnected systems.

Reliability Standards

I. Installed Generating Capacity Requirements

Sufficient megawatt generating capacity shall be installed to insure that in each year for the MAAC system the probability of occurrence of load exceeding the available generating capacity shall not be greater, on the average, than one day in ten years. Among the factors to be considered in the calculation of the probability are the characteristics of the loads, the probability of error in load forecast, the scheduled maintenance requirements for generating units, the forced outage rates of generating units, limited energy capacity, the effects of connections to other pools, and network transfer capabilities within the MAAC systems.

II. Transmission Requirements

The bulk transmission system shall be developed so that it can be operated at all load levels to meet the following unscheduled contingencies without instability, cascading or interruption of load:

A. The loss of any single generating unit, transmission line, transformer, or bus in addition to normal scheduled outages of bulk

electric supply system facilities without exceeding the applicable emergency rating of any facility. After the outage, the system must be capable of readjustment so that all equipment (on the MAAC and neighboring systems) will be loaded within normal ratings.

B. After occurrence of the outage and the readjustment of the system specified in A, the subsequent outage of any remaining generator or line without exceeding the short time emergency rating of any facility. After this outage, the system must be capable of readjustment so that all remaining equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

C. The loss of any double circuit line or the combination of facilities resulting from a line fault and a stuck breaker in addition to normal scheduled generator outages without exceeding the short time emergency rating of any facility. After the outage, the system must be capable of readjustment so that all equipment will be loaded within applicable emergency ratings for the probable duration of the outage.

In determining the bulk transmission requirements, recognition shall be given to the occurrence of similar contingencies in neighboring systems and their effect on the MAAC system.

III. General Requirements

Sufficient megavar capacity with adequate controls shall be installed in each system to supply the reactive load and loss requirements in order to maintain acceptable emergency transmission voltage profiles during all the above contingencies.

Installation of generation and transmission facilities shall be coordinated to insure that in each year for each member system the probability of occurrence of load exceeding the available capacity resources shall not be greater, on the average, than one day in ten years. Available capacity resources consist of the generating capability available internal to the member system and the capacity that can be transmitted into the member system. (See Section VII.)

IV. Stability Requirements

The stability of the system shall be maintained without loss of load during and after the following types of faults occurring at the most critical location at all load levels.

A. A three-phase fault with normal clearing time.

B. Single phase-to-ground fault with a stuck breaker or other cause for delayed clearing.

V. Tests for Ability of MAAC System to Withstand Abnormal Disturbances

The MAAC group recognizes that it is impossible to anticipate or test for all the contingencies that can occur on the present and future MAAC system. These tests, therefore, serve primarily as a means to measure the ability of the system to withstand less probable contingencies, some of which may not be readily apparent. These tests are prescribed not on the basis of a high level of probability, but rather as a practical means to study the system for its ability to withstand disturbances beyond those which can reasonably be expected. The MAAC system, therefore, will be tested to determine the effect of various types of contingencies on system performance. Examples of less probable contingencies to be studied are:

A. Sudden loss of the entire generating capability for any station for any reason.

B. The outage of the most critical transmission line on any one of the interconnected systems as the result of a three-phase fault immediately following (i.e., before readjustment) the tripping of another critical line on the same or on an adjacent system.

C. The sudden loss of all lines of one voltage emanating from a substation.

D. The sudden loss of all lines on a single right of way.

E. The sudden dropping of a large load or a major load center.

F. The occurrence of a multi-phase fault with delayed clearing.

VI. Relaying and Protective Devices

Independent devices shall be installed to the extent necessary to provide backup for the primary protective devices and components so as to limit equipment damage, to limit the shock to the system and to speed restoration of service.

Relaying installed shall not restrict the normal or the necessary realizable network transfer capabilities of the system.

Underfrequency relays shall be installed to provide additional insurance against widespread sys-

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tem disturbances. They shall not be used to satisfy the contingencies listed under Sections I and II.

VII. Network Transfer Capability

The amounts of power planned to be interchanged between areas within MAAC and between MAAC and neighboring pools shall be such that applicable ratings and stability, voltage and relay limitations are not exceeded.

A. Extended Period Transfer

The maximum amount of capacity planned to be delivered from one area to another for economy interchange in normal day-to-day operations shall be limited as follows:

1. With all transmission facilities in service and normal generator maintenance scheduling, all system components shall be within normal loading limits.
2. With the outage of any single facility, the provisions of Section II A shall apply.

B. Capacity Emergency Transfer

The maximum amount of capacity planned to be transferred from one area to another for capacity shortages shall be limited as follows:

1. With all transmission facilities in service and normal generator maintenance schedules, the loadings of all system components shall be within applicable emergency ratings and stability limits and no excessive voltage drops shall occur.
2. The interconnected systems shall then be able to absorb the initial power swing resulting from the sudden loss of any one transmission line or generating unit.
3. After the initial swing period, the loadings of all system components shall be within short time emergency ratings and acceptable voltage limits.

APPENDIX D

STRUCTURE OF THE INDUSTRY

Coordinating Organizations

Northeast Power Coordinating Council

Boston Edison Company
Burlington Electric Light Department
Central Hudson Gas & Electric Corporation
Central Maine Power Company
Central Vermont Public Service Corporation
Consolidated Edison Company of New York
Eastern Utilities Associates
Green Mountain Power Corporation
Hydro-Electric Power Commission of Ontario
Long Island Lighting Company
New England Electric System
New England Gas and Electric Association
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Northeast Utilities
Orange and Rockland Utilities
Power Authority of the State of New York
Public Service Company of New Hampshire
Rochester Gas and Electric Corporation
United Illuminating Company

Mid-Atlantic Area Coordination Agreement

Atlantic City Electric Company
Baltimore Gas and Electric Company
Delmarva Power & Light Company
Jersey Central Power & Light Company
Metropolitan Edison Company
New Jersey Power & Light Company
Pennsylvania Electric Company
Pennsylvania Power & Light Company
Philadelphia Electric Company
Potomac Electric Power Company
Public Service Electric and Gas Company
UGI Corporation

Pools

New England Power Pool

Boston Edison Company
Central Maine Power Company
Central Vermont Public Service Company
Eastern Utilities Associates
New England Electric System
New England Gas and Electric Association
Northeast Utilities
Public Service Company of New Hampshire
United Illuminating Company

New York Power Pool

Central Hudson Gas & Electric Corporation
Consolidated Edison Company
Long Island Lighting Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Orange and Rockland Utilities
Power Authority of the State of New York
Rochester Gas and Electric Corporation

Pennsylvania-New Jersey-Maryland Interconnections

Public Service Electric and Gas Company
Philadelphia Electric Company Group
    Philadelphia Electric Company
    Atlantic City Electric Company
    Delmarva Power & Light Company
Pennsylvania Power & Light Company
    Pennsylvania Power & Light Company
    UGI Corporation
Baltimore Gas and Electric Company
General Public Utilities System
    Jersey Central Power & Light Company
    Metropolitan Edison Company
    New Jersey Power & Light Company
    Pennsylvania Electric Company
Potomac Electric Power Company

Structure of the Northeast Power Supply

Company or Agency	State	Installed generating capacity (Kw) Private	Govt. or Coop.
Study Area A—Year end 1967			
Northeast Utilities	Mass. & Conn	2, 505, 076	
New England Electric System	Mass., Vt., N.H., R.I	1, 725, 563	
Boston Edison	Massachusetts	1, 981, 744	
Central Maine Power	Maine	655, 260	
United Illuminating	Connecticut	602, 186	
Public Service of New Hampshire	New Hampshire	432, 386	
Eastern Utility Associates	Massachusetts	393, 350	
New England Gas & Electric	Massachusetts	223, 867	
Bangor Hydro Electric	Maine	130, 897	
Central Vermont Public Service	Vermont	90, 030	
Green Mountain Power	Vermont	53, 080	
Taunton Municipal	Massachusetts		77, 300
Holyoke Gas & Electric	Massachusetts		42, 906
Fitchburg Gas & Electric	Massachusetts	61, 385	
Braintree Electric	Massachusetts		38, 830
Rumford Falls Power	Maine	34, 770	
Maine Public Service	Maine	36, 400	
Burlington Electric	Vermont		30, 000
Wallingford Boro	Connecticut		22, 500
Newport Electric	Rhode Island	18, 500	
Hudson Light & Power	Massachusetts		19, 850
Norwich Gas & Electric	Connecticut		17, 250
Citizens Utilities	Vermont	13, 980	
Ipswich Water & Light	Massachusetts		10, 280
South Norwalk Electric	Connecticut		9, 195
Farmington River	Connecticut	8, 000	
Peabody Electric	Massachusetts		11, 150
Swanton Village	Vermont		4, 600
Nantucket Gas & Electric	Massachusetts	7, 950	
Morrisville Village	Vermont		3, 100
Wolfeboro Municipal	New Hampshire		3, 016
Barton Village	Vermont		1, 400
Eastern Maine Electric Coop	Maine		2, 500
Enosburg Falls	Vermont		1, 640
City of Providence	Rhode Island		4, 000
Vinalhaven Light	Maine	1, 223	
Island Light	Rhode Island	1, 471	
Hardwick Village	Vermont		1, 375
Lubec Water & Electric	Maine		1, 290
Marblehead Light	Massachusetts		1, 136
Lyndonville Electric	Vermont		950
Bangor Electric (City of)	Maine		700
Lewiston Water	Maine		700
White Mountain Power	Vermont		500
Madison Electric	Maine		500
Woodsville Light	New Hampshire		400
Littleton Water & Light	New Hampshire		300
Rangeley Power	Maine	250	
Bozrah Light	Connecticut	250	
Kennebunk Light	Maine		150
Swan's Island Electric Coop	Maine		350

Structure of the Northeast Power Supply—Continued

Company or Agency	State	Installed generating capacity (Kw) Private	Installed generating capacity (Kw) Govt. or Coop.
Study Area A—Year end 1967—Continued			
Connecticut Yankee	Connecticut	600, 300	
Yankee Atomic	Massachusetts	185, 000	
Fisher's Island Electric	New York	1, 800	
Total		9, 764, 718	307, 868
Percentage of Total		96. 9	3. 1
Study Area B—Year end 1967			
Consolidated Edison Co. of New York	New York	7, 806, 152	
Power Authority of the State of New York	New York		3, 102, 000
Niagara Mohawk	New York	2, 886, 139	
Long Island Lighting Company	New York	1, 919, 874	
New York State Electric & Gas	New York	759, 488	
Rochester Gas & Electric	New York	519, 190	
Central Hudson Gas & Electric	New York	590, 230	
Orange and Rockland Utilities	New York	338, 270	
Jamestown Municipal Electric	New York		57, 500
Rockville Centre	New York		26, 588
Freeport	New York		13, 105
Greenport	New York		5, 595
Watertown Municipal Electric	New York		5, 400
Lawrence Park Heat Light & Power	New York	1, 600	
Springville	New York		500
Lake Placid Municipal	New York		332
Philadelphia	New York		128
Dexter Hydro Electric Corp	New York	2, 940	
Gouverneur, Village of	New York		160
New York State Dept. of Public Works	New York		11, 200
Potsdam, Village of	New York		187
Skaneateles Municipal	New York		376
Theresa	New York		130
Plattsburgh	New York		3, 236
Total		14, 823, 883	3, 226, 437
Percentage of Total		82. 1	17. 9
Study Area C—Year end 1967			
Public Service Electric and Gas	New Jersey	5, 450, 484	
Philadelphia Electric Company	Pennsylvania	4, 685, 830	
General Public Utilities	Pa. & N.J.	3, 042, 674	
Pennsylvania Power & Light	Pennsylvania	2, 348, 060	
Potomac Electric Power	District of Columbia	2, 394, 900	
Baltimore Gas and Electric	Maryland	2, 094, 650	
Delmarva Power & Light	Delaware	905, 899	
Atlantic City Electric	New Jersey	710, 594	
UGI Corp	Pennsylvania	93, 000	
Vineland Electric	New Jersey		52, 250
Lansdale Electric	Pennsylvania		35, 750
Dover	Delaware		46, 250
Easton Utilities	Maryland		16, 375

Structure of the Northeast Power Supply—Continued

Company or Agency	State	Installed generating capacity (Kw) Private	Govt. or Coop.
Study Area C—Year end 1967—Continued			
Quakertown Municipal	Pennsylvania		9, 900
Seaford	Delaware		7, 302
South River	New Jersey		6, 195
Berlin	Maryland		4, 148
Girard Municipal	Pennsylvania		4, 139
Weatherly Borough	Pennsylvania		2, 000
Hatfield Municipal	Pennsylvania		2, 685
Centreville	Maryland		3, 150
Lewes	Delaware		3, 438
Passaic Valley	New Jersey		2, 400
Pemberton	New Jersey		810
Accomack-Northampton Electric Coop	Virginia		2, 403
Safe Harbor	Pennsylvania	230, 000	
Bethlehem Steel Corp	Maryland	158, 500	
Hershey Foods Corp	Pennsylvania	25, 000	
Total		22, 139, 615	198, 595
Percentage of Total		99. 1	0. 9

APPENDIX E

COMMITTEE MEMBERSHIPS

Northeast Regional Advisory Committee

H. J. Cadwell [1]
174 Brush Hill Avenue
West Springfield, Mass. 01089

E. R. Acker, Chairman
Northeast Power Coordinating Council
284 South Avenue
Poughkeepsie, N.Y. 12602

Brendan T. Byrne [2], President
New Jersey Board of Public Utility Commissioners
Rm. 316, State House Annex
Trenton, N.J. 08625

W. S. Chapin, General Manager & Chief Engineer
Power Authority of the State of N.Y.
10 Columbus Circle
New York, N.Y. 10019

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Vermont Electric Cooperative, Inc.
School Street
Johnson, Vt. 05656

T. C. Duncan, Senior Vice President
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, N.Y. 10003

W. H. Dunham, President
Central Maine Power Company
9 Green Street
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Emerson Harper, Engineering Assistant
Office of Asst. Sec'y for Water & Power
Department of the Interior
Washington, D.C. 20240

Russel Hicock [5], Senior Vice President
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176 Cumberland Avenue
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F. H. King, Manager
Holyoke Municipal Gas & Electric Department
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M. H. Pratt, Vice President
Niagara Mohawk Power Corporation
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Syracuse, N.Y. 13202

Edwin H. Snyder [3], Chairman of the Board
Public Service Electric & Gas Co.
80 Park Place
Newark, N.J. 07101

Stephen R. Woodzell [4], President
Potomac Electric Power Company
929 E Street, N.W.
Washington, D.C. 20004

NERAC Report Coordinating Committee

M. H. Pratt, Vice President [6]
Niagara Mohawk Power Corporation
300 Erie Blvd. W.
Syracuse, N.Y. 13202

T. C. Dunham, President
Central Maine Power Company
9 Green Street
Augusta, Maine 04330

[1] Formerly Chairman of the Board, Western Massachusetts Electric Co., now retired. Chairman of NERAC from January 10, 1966 to close of meeting May 21, 1968.

[2] Succeeded William F. Hyland, who resigned in January, 1968.

[3] Chairman of NERAC effective May 21, 1968.

[4] Succeeded R. R. Dunn, who resigned August 1, 1966.

[5] Appointed September 13, 1968 to fill vacancy created by Mr. Cadwell's resignation.

[6] Chairman of Committee.

F. H. King, Manager
Holyoke Municipal Gas & Electric Department
70 Suffolk Street
Holyoke, Mass. 01040

S. R. Woodzell, President
Potomac Electric Power Company
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Task Forces

Load Forecast Task Force

J. A. Casazza (Study Area C)
Public Service Electric and Gas Co.
Newark, N.J. 07101

J. J. Drummond (Power Supply Area 4)
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E. L. Hoffman (Power Supply Area 3)
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P. J. Sullivan (Study Area A)
Western Massachusetts Electric Co.
174 Brush Hill Avenue
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Hydro-Electric Peaking and Quick Start Generation Task Force

William S. Chapin [7]
Power Authority of the State of New York
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W. J. Burns, Manager
Long Island Lighting Company
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Roger D. Ley
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Jack R. Templeton
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Bulk Power Transmission Task Force

Wells P. Allen, Jr.
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David Hayward
Eastern Mass-Vermont Energy Control
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Wei Shing Ku
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Newark, N.J. 07101

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Pennsylvania Power & Light Company
Allentown, Pa. 18101

B. O. McCoy
Vermont Electric Power Company, Inc.
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Base Load Generation Task Force

W. L. Ridenhour [8]
Baltimore Gas and Electric Company
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Baltimore Gas and Electric Company
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S. C. Millspaugh
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[7] Chariman of Task Force. Asa George, Ass't. Chief Engineer, substituted on some occasions.
[8] Chairman of Task Force.

J. J. Ray
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1000 Chestnut St., Philadelphia, Pa. 19105

B. H. Weiner
Boston Edison Company
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Fossil Fuel Resources Committee
Northeast, East Central and Southeast Regions

John F. Campbell[9]
Consolidated Edison Company of New York, Inc.
4 Irving Place, New York, N.Y. 10003

Kurt Brenner
Public Service Electric and Gas Company
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Earl F. Brush
Hamilton Department of Public Utilities
High Street & Monument Ave.,
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Alexander Gakner
Federal Power Commission
441 G Street, N.W., Washington, D.C. 20426

[9] Chairman of Committee.

Thomas W. Hunter
Bureau of Mines, Department of the Interior
Room 4415, Washington, D.C. 20240

Alfred J. Ormston
Florida Power Corporation
P.O. Box 14042, St. Petersburg, Fla. 33733

Thomas H. Pofahl
Office of Oil and Gas, Department of the Interior
Room 5508, Washington, D.C. 20240

John P. Gallagher, Piqua (Ohio) Municipal Plant, previous member of the Committee, resigned due to change of employment.

MAJOR GENERATING STATIONS

(400 MEGAWATTS AND OVER)

*CODE	PLANT NAME	CA… 1970
	□ CONVENTIONAL HYDROELECTRIC	
A	MOSES-NIAGARA	1,950
B	MOSES-ST. LAWRENCE	912
C	SAFE HARBOR-CONOWINGO [1]	812
D	DICKEY-LINCOLN SCHOOL	
	◇ PUMPED STORAGE HYDROELECTRI…	
A	MUDDY RUN	800
B	NORTHFIELD MT.	
C	BEAR SWAMP	
D	HOUSATONIC AREA	
E	CORNWALL	
F	KITTATINNY MT.	
G	STONY CREEK	
H	GILBOA	
I	ROWE	
J	BERLIN	
K	EASTERN NEW YORK	
L	WESTERN NEW YORK	
M	CENTRAL NEW YORK	
N	WYCOFF RUN-MIX RUN	
	△ NUCLEAR FUELED STEAM-ELECTRIC	
A	HADDAM NECK	600
B	MILLSTONE	650
C	INDIAN POINT	1,361
D	NINE MILE POINT	626
E	GINNA	517
F	OYSTER CREEK	640
G	PEACH BOTTOM	[5]
H	BAILEY POINT	
I	NEWINGTON	
J	PILGRIM	
K	VERNON	
L	BOSTON AREA	
M	TROY	
N	BELL	
O	SHOREHAM	
P	N.Y.C. AREA	
Q	NORTHEAST N.J.	
R	PHILADELPHIA AREA	
S	SOUTHWEST N.J.	
T	RED LION	
U	BUSH RIVER	
V	CALVERT CLIFFS	
W	CHALK POINT AREA	
X	THREE MILE ISLAND-SALEM	
Y	MESHOPPEN	
Z	BUFFALO AREA	
AA	POINT PLEASANT AREA	
AB	EASTERN SHORE, MD.	
AC	MORGANTOWN AREA	
AD	DICKERSON AREA	
AE	READING-ALLENTOWN AREA	
AF	LAKE CHAMPLAIN	
AG	CONNECTICUT	
AH	PROVIDENCE AREA	
AI	SOUTHWEST MAINE	
	○ CONVENTIONAL STEAM-ELECTRIC [2]	
A	MERRIMACK	489 [5]
B	SALEM HARBOR	
C	MYSTIC	636
D	NEW BOSTON	718
E	EDGAR	491
F	CANAL	515
G	BRAYTON POINT	1,088 [5]
H	MONTVILLE	
I	MIDDLETOWN	441
J	DEVON	470
K	BRIDGEPORT HARBOR	655
L	ALBANY	521
M	C. R. HUNTLEY	829
N	DUNKIRK	629
O	DANSKAMMER	538
P	LOVETT	490
Q	WATERSIDE	727
R	EAST RIVER	834
S	ARTHUR KILL	912
T	RAVENSWOOD	1,844
U	ASTORIA	1,567
V	GLENWOOD	413
W	NORTHPORT	403
X	PORT JEFFERSON	483
Y	E. F. BARRETT	538
Z	BERGEN	669
AA	HUDSON	1,190
AB	KEARNY	534
AC	LINDEN	539
AD	SEWAREN	926
AE	MERCER	767
AF	BURLINGTON	510
AG	PORTLAND	443
AH	DELAWARE	481
AI	SOUTHWARK	422
AJ	EDDYSTONE	744
AK	CROMBY	421
AL	BRUNNER ISLAND	1,567
AM	SUNBURY	416
AN	MONTOUR	
AO	SHAWVILLE	631
AP	KEYSTONE	1,883
AQ	HOMER CITY	1,286
AR	CONEMAUGH	876
AS	EDGEMOOR	405
AT	CHARLES P. CRANE	416
AU	HERBERT A. WAGNER	644
AV	DICKERSON	603
AW	BUZZARD POINT	538
AX	BENNING	553
AY	POTOMAC RIVER	515
AZ	MORGANTOWN	608
BA	CHALK POINT	728
BB	PENN MINE MOUTH	
BC	HARRISBURG AREA	
BD	READING-ALLENTOWN AREA	
	TOTAL MAJOR STATIONS	44,414

1 THREE PROJECTS IN SAME STRETCH OF LOWER SUSQ… ESSENTIALLY AS SINGLE PLANT.
2 INCLUDES EXISTING AND SCHEDULED IC/GT CAPAC… SCHEDULED GENERATING STATIONS.
3 "STRETCH RATING" OF UNITS USED WHERE AVAILAB…
4 REFLECTS SCHEDULED RETIREMENTS TO 1970 AND AS… ON BASIS OF 50 YEAR SERVICE LIFE AFTER 1970.
5 EXISTING STATION (1968) UNDER 400 MW.

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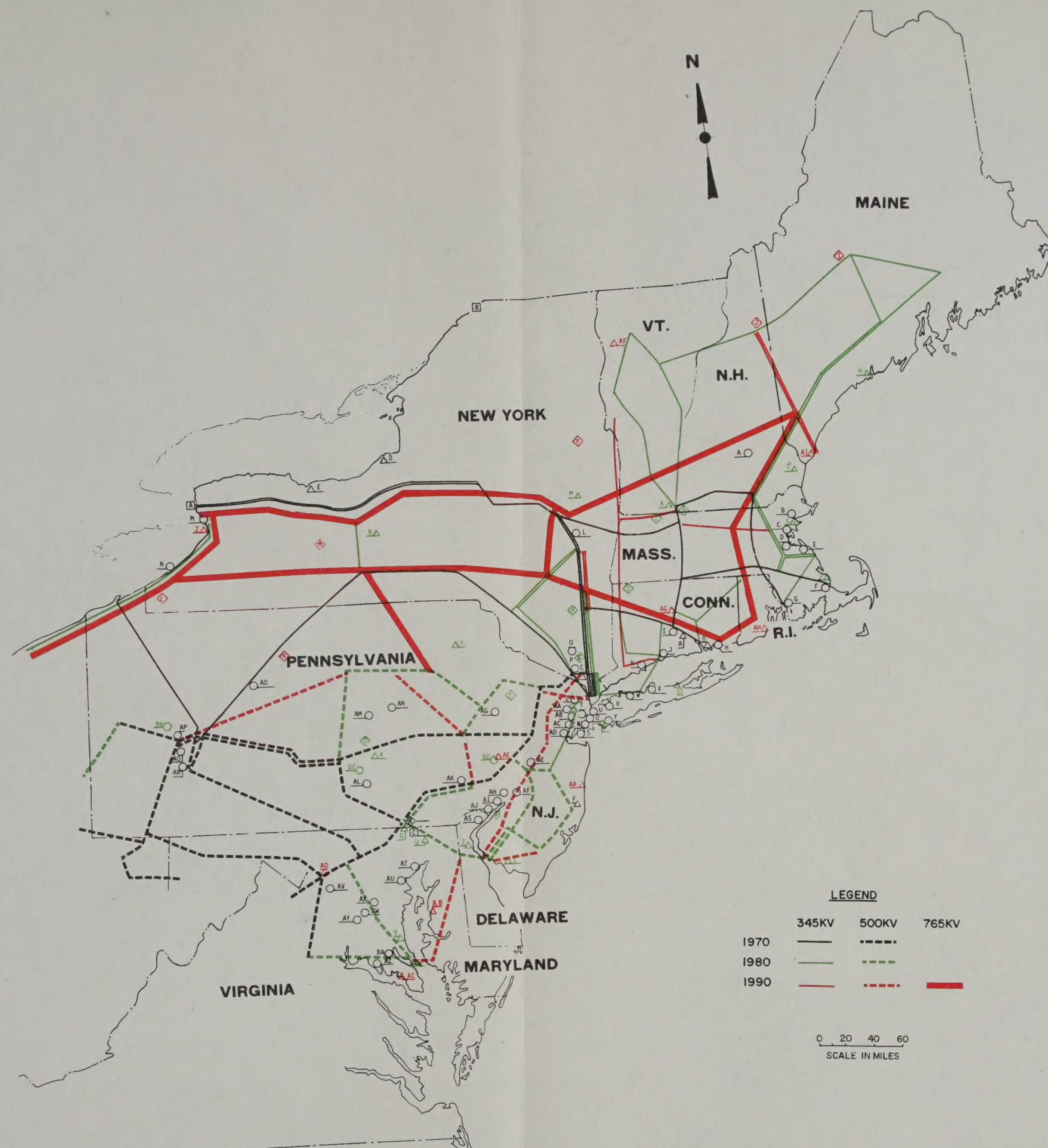
MAJOR GENERATING STATIONS
(400 MEGAWATTS AND OVER)

*CODE	PLANT NAME	CAPACITY-MW 1970	1980	1990
	☐ CONVENTIONAL HYDROELECTRIC			
A	MOSES-NIAGARA	1,950	1,950	1,950
B	MOSES-ST. LAWRENCE	912	912	912
C	SAFE HARBOR-CONOWINGO [1]	812	1,149	1,149
D	DICKEY-LINCOLN SCHOOL		830	830
	◇ PUMPED STORAGE HYDROELECTRIC			
A	MUDDY RUN	800	800	800
B	NORTHFIELD MT.		1,000	1,500
C	BEAR SWAMP		600	600
D	HOUSATONIC AREA		1,000	1,000
E	CORNWALL		2,000	2,000
F	KITTATINNY MT.		1,350	1,350
G	STONY CREEK		1,000	1,000
H	GILBOA		1,000	1,000
I	ROWE			1,000
J	BERLIN			500
K	EASTERN NEW YORK			1,000
L	WESTERN NEW YORK			1,000
M	CENTRAL NEW YORK			1,000
N	WYCOFF RUN-MIX RUN			1,000
	△ NUCLEAR FUELED STEAM-ELECTRIC [2] [3]			
A	HADDAM NECK	600	600	600
B	MILLSTONE	650	2,678	4,678
C	INDIAN POINT	1,361	2,430	2,430
D	NINE MILE POINT	626	2,626	3,626
E	GINNA	517	1,517	3,517
F	OYSTER CREEK	640	1,560	1,560
G	PEACH BOTTOM	[5]	2,177	2,177
H	BAILEY POINT		855	855
I	NEWINGTON		800	2,800
J	PILGRIM		1,454	1,454
K	VERNON		1,740	1,740
L	BOSTON AREA		3,000	10,500
M	TROY		790	2,790
N	BELL		853	1,853
O	SHOREHAM		553	553
P	N.Y.C. AREA		4,378	17,378
Q	NORTHEAST N.J.		1,000	9,000
R	PHILADELPHIA AREA		4,000	10,500
S	SOUTHWEST N.J.		2,100	5,100
T	RED LION		1,000	4,000
U	BUSH RIVER		1,000	2,500
V	CALVERT CLIFFS		1,730	3,230
W	CHALK POINT AREA		1,000	1,000
X	THREE MILE ISLAND-SALEM		840	3,840
Y	MESHOPPEN		500	500
Z	BUFFALO AREA			2,000
AA	POINT PLEASANT AREA			3,000
AB	EASTERN SHORE, MD.			1,500
AC	MORGANTOWN AREA			3,000
AD	DICKERSON AREA			6,000
AE	READING-ALLENTOWN AREA			1,500
AF	LAKE CHAMPLAIN			2,000
AG	CONNECTICUT			2,000
AH	PROVIDENCE AREA			2,000
AI	SOUTHWEST MAINE			2,000
	○ CONVENTIONAL STEAM-ELECTRIC [2] [4]			
A	MERRIMACK	489 [5]	489	989
B	SALEM HARBOR		720	720
C	MYSTIC	636	636	636
D	NEW BOSTON	718	718 [5]	718 [5]
E	EDGAR	491		
F	CANAL	515	1,715	1,715
G	BRAYTON POINT	1,088 [5]	1,088	1,088
H	MONTVILLE		554	554
I	MIDDLETOWN	441	441	441
J	DEVON	470	445	445
K	BRIDGEPORT HARBOR	655	655	1,155
L	ALBANY	521	521	521
M	C. R. HUNTLEY	829	829	829
N	DUNKIRK	629	629	629
O	DANSKAMMER	538	538	538
P	LOVETT	490	490	490
Q	WATERSIDE	727	657	501
R	EAST RIVER	834	513	513
S	ARTHUR KILL	912	912	912
T	RAVENSWOOD	1,844	1,844	1,844
U	ASTORIA	1,567	1,567 [4]	1,567 [4]
V	GLENWOOD	413		
W	NORTHPORT	403	403	403
X	PORT JEFFERSON	483	483	483
Y	E. F. BARRETT	538	538	538
Z	BERGEN	669	669	669
AA	HUDSON	1,190	1,190	1,190
AB	KEARNY	534	534	534
AC	LINDEN	539	539	539
AD	SEWAREN	926	926	926
AE	MERCER	767	767	767 [5]
AF	BURLINGTON	510	480	
AG	PORTLAND	443	443 [4]	443 [4]
AH	DELAWARE	481		
AI	SOUTHWARK	422	422	422
AJ	EDDYSTONE	744	744	744
AK	CROMBY	421	421	421
AL	BRUNNER ISLAND	1,567	1,567	1,567
AM	SUNBURY	416	416	416
AN	MONTOUR		1,910	1,910
AO	SHAWVILLE	631	631	631
AP	KEYSTONE	1,883	1,883	1,883
AQ	HOMER CITY	1,286	1,286	1,286
AR	CONEMAUGH	876	1,741	1,741
AS	EDGEMOOR	405	405	405
AT	CHARLES P. CRANE	416	416	416
AU	HERBERT A. WAGNER	644	644	644
AV	DICKERSON	603	603	603
AW	BUZZARD POINT	538	538 [4]	418 [4]
AX	BENNING	553		
AY	POTOMAC RIVER	515	515	515
AZ	MORGANTOWN	608	1,183	1,183
BA	CHALK POINT	728	728	728
BB	PENN MINE MOUTH		3,000	6,000
BC	HARRISBURG AREA		2,840	2,840
BD	READING-ALLENTOWN AREA		840	1,840
	TOTAL MAJOR STATIONS	44,414	100,438	184,129

1 THREE PROJECTS IN SAME STRETCH OF LOWER SUSQUEHANNA OPERATED ESSENTIALLY AS SINGLE PLANT.
2 INCLUDES EXISTING AND SCHEDULED IC/GT CAPACITY AT EXISTING AND SCHEDULED GENERATING STATIONS.
3 "STRETCH RATING" OF UNITS USED WHERE AVAILABLE.
4 REFLECTS SCHEDULED RETIREMENTS TO 1970 AND ASSUMED RETIREMENTS ON BASIS OF 50 YEAR SERVICE LIFE AFTER 1970.
5 EXISTING STATION (1968) UNDER 400 MW.



NORTHEAST REGIONAL ADVISORY COMMITTEE
PRINCIPAL ELECTRIC FACILITIES IN REGION I

Figure 17

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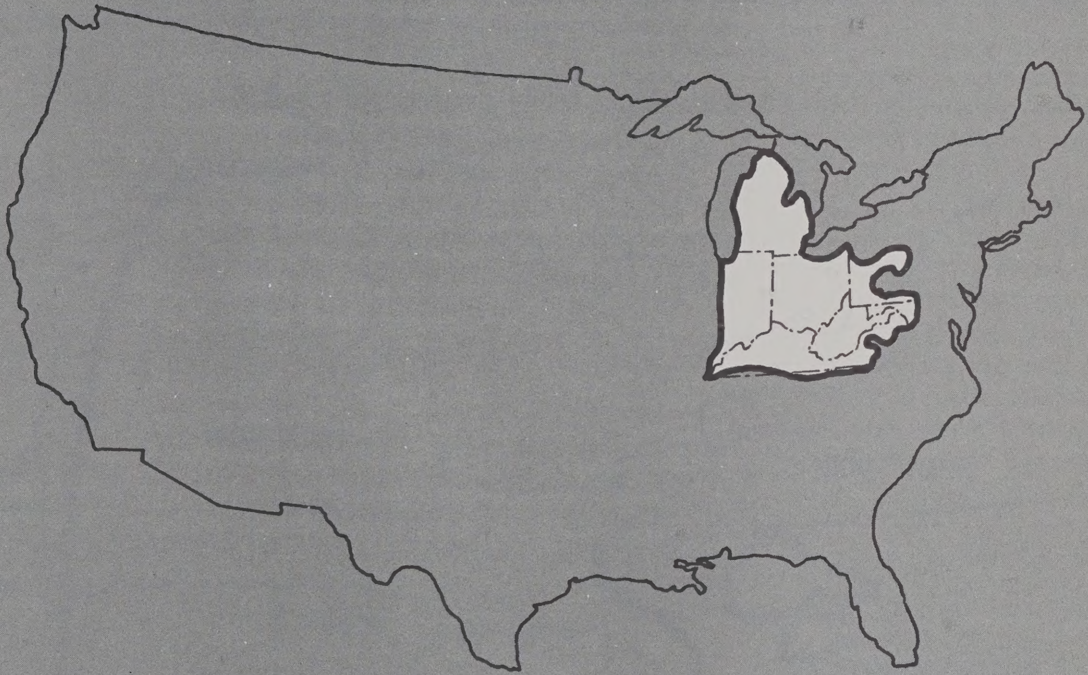
ELECTRIC POWER IN THE EAST CENTRAL REGION

1970–1980–1990



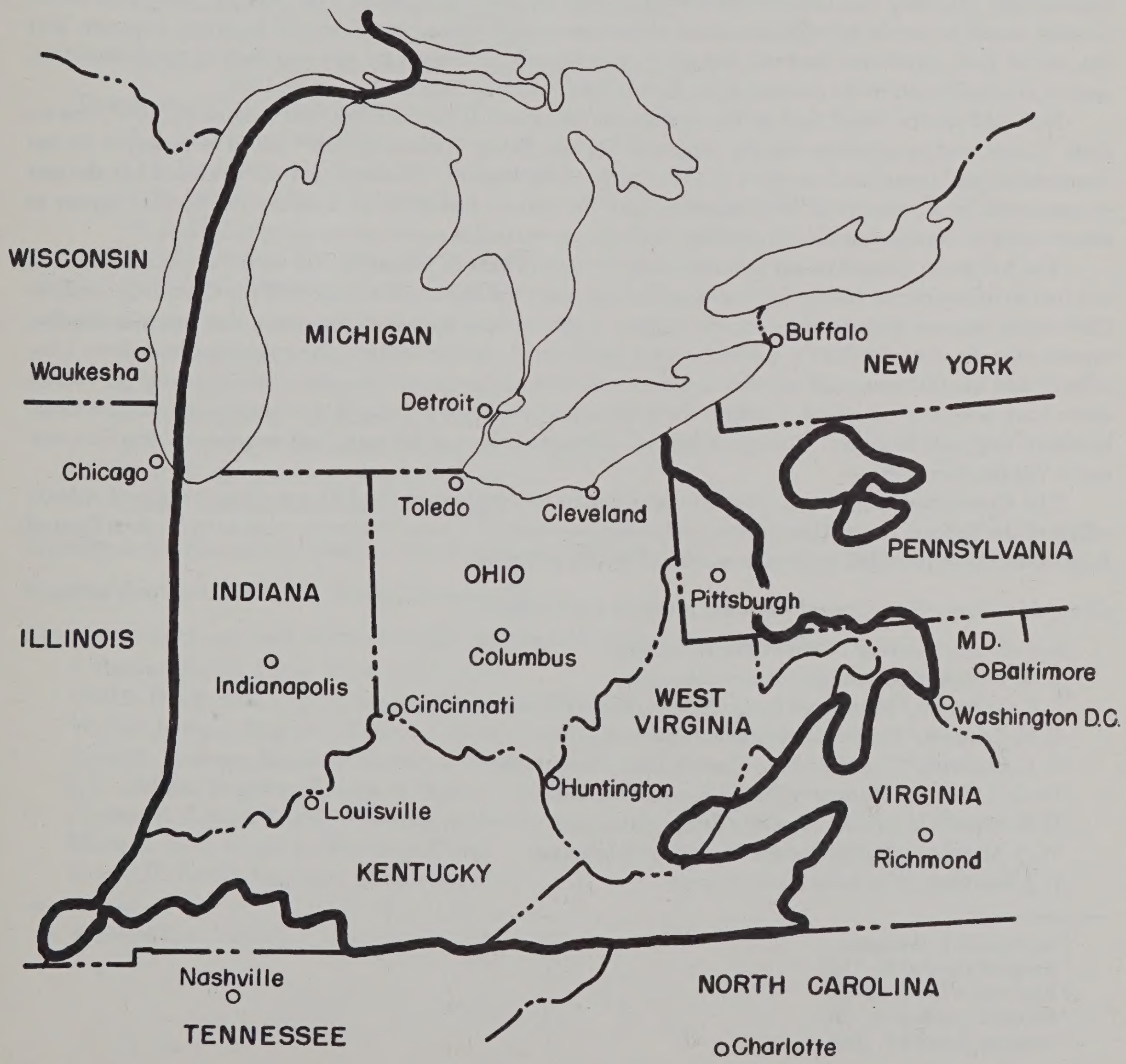
A REPORT
to the FEDERAL POWER COMMISSION
prepared by
THE EAST CENTRAL REGIONAL ADVISORY COMMITTEE

DECEMBER 1969

PREFACE

This Report has been prepared and is being submitted to the Federal Power Commission (Commission) and its Executive Advisory Committee pursuant to the provisions of the Commission's "Order Establishing National Power Survey Regional Advisory Committees," issued January 10, 1966, and order of the Commission, dated December 20, 1967, continuing the existence of such Regional Advisory Committees.

The East Central Regional Advisory Committee (Committee) is one of the six Regional Committees appointed by the Commission pursuant to its order dated January 10, 1966, to assist the Commission and the Executive Advisory Committee in its work with and for the Commission, specifically, among other things, in updating the National Power Survey, a report issued by the Commission in December 1964. The area represented by the Committee is the East Central Region (Region II) as delineated by the Commission pursuant to Section 202(a) of the Federal Power Act, as shown below.



The Committee has had 15 meetings, the first of which was held on April 18, 1966. The membership has undergone several changes since the Committee's appointment, and a list of the Committee's membership is contained below. In addition to the Committee members, the meetings were regularly attended by Commission Staff personnel, including the Commission's Regional Engineer and the Committee's Secretary, a Commission Staff member.

While the Committee (through task forces and/or subgroups) prepared reports on Design and Operating Practices and Avoided Interruptions for possible use in the preparation of the Commission's Report on Reliability of Bulk Power Supply, issued in July 1967, its principal activities have been in four areas, namely, fuel resources; load projections; patterns of generation and transmission; and coordinated planning and development. A task force was appointed to prepare a report covering each of the four topics and the reports of these task forces have formed the basis for this report. The task force on Fuel Resources was a joint task force for the East Central, Southeast, and Northeast Regional Advisory Committees. (Membership lists of these task forces are contained below.)

Guidelines were prepared by the Commission's Staff for the use of each task force and were revised and supplemented from time to time.

A majority of the Committee took issue with certain portions of the Staff's Guidelines For Study of Coordinated Planning and Development by Regions (Revised Draft, dated February 21, 1967). No useful purpose would be served by repeating these objections and criticisms here. It should be noted, however, that the text of such comments, and the text of dissents to such comments by two members of the Committee, appear as attachments to the minutes of the Committee's meeting held on August 24, 1967.

It should also be noted that on the agenda for discussion at the meeting held August 24, 1967, was an item "Comments or questions on the proposed Electric Power Reliability Act" (S. 1934 prepared by the Commission and introduced on June 7, 1967, in the U.S. Senate). This item was not discussed but the text of comments by a majority of the Committee and the text of dissents to such comments likewise appear as attachments to the minutes of such meeting. Including them in this report seems not appropriate.

The foregoing comments are included here to explain that in preparing this report the Committee has felt free to follow or not follow the Staff's guidelines, since this report is the report of the Committee and the Committee assumes responsibility for its content. It should be emphasized, however, that, notwithstanding certain objections to the Staff's guidelines by a majority of the Committee, the guidelines have been most helpful and the differences of opinion between members of the Committee and Staff personnel on various items have been the exception. Further, the Committee has received complete cooperation from the Commission's Regional Engineer, Chicago Regional Office, members of his staff, and members of the Commission's Washington staff.

The Committee wishes to express its appreciation to members of the Chicago, New York and Atlanta offices of the Federal Power Commission and to the personnel of the several power systems in the East Central Region who have provided invaluable assistance in this endeavor.

List of Members—East Central Regional Advisory Committee:

E. F. Brush,[1] Lansing Board of Water & Light
J. H. Campbell, Consumers Power Company
J. P. Gallagher,[2] Municipal Power System, Piqua, Ohio
C. R. Johnson,[3] Public Utilities Commission of Ohio
E. L. Lindseth,[4] The Cleveland Electric Illuminating Co.
Wells T. Lovett,[5] Kentucky Public Service Commission
D. B. Mansfield, Chairman, Ohio Edison Company
W. J. Matthews, Public Service Company of Indiana
F. J. McAlary, Allegheny Power System

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[1] Replaced J. P. Gallagher.
[2] Resigned October 25, 1967.
[3] Replaced Wells T. Lovett.
[4] Resigned January 10, 1967.
[5] Resigned January 5, 1968.

T. J. Nagel,[6] American Electric Power Service Corp.
H. L. Spurlock, East Kentucky RECC

List of Members of Task Forces:

Load Projection:

H. L. Spurlock, Chairman
R. H. Breckenkamp, East Kentucky RECC
H. J. Stemm, Ohio Municipal Electric Association
W. J. Mosley, Consumers Power Company
R. H. Travers, Ohio Edison Company
Dale McLeod, Hoosier Energy Division

Fuel Resources (Joint with Northeast and Southeast Advisory Committees):

J. F. Campbell, Chairman, Consolidated Edison Company
Kurt Brenner, Public Service Electric & Gas Co.
E. F. Brush (J. P. Gallagher), Lansing Board of Water & Light
Alex Gakner, Federal Power Commission
Thomas Hunter, Bureau of Mines, Dept. of the Interior
A. J. Ormston, Florida Power Corporation
Thomas H. Pofahl, Office of Oil & Gas, Dept. of the Interior

Coordinated Planning and Development:

F. J. McAlary, Chairman
C. J. Frederickson, Ohio Edison Company
C. R. Johnson (Wells T. Lovett)
W. J. Matthews
J. F. McQuillin, Allegheny Power System
H. R. Wall, Consumers Power Company

Patterns of Generation and Transmission:

W. J. Matthews, Chairman
J. F. McQuillin, Allegheny Power System
L. M. Ramsdell, East Kentucky RECC
S. W. Shields, Public Service Company of Indiana
H. R. Wall, Consumers Power Company
Lynn Firestone, Ohio Edison Company

Secretary to the Committee: David L. Simon, Chicago, Illinois

Regional Engineer: Lenard B. Young, Chicago, Illinois

Commission Staff members who customarily attended meetings of the Committee:

F. Stewart Brown, Chief, Bureau of Power
Orel E. Haukedahl, Deputy Regional Engineer, Chicago
Warren Jackson, Engineer, Bureau of Power
Cleve R. Jacobsen, Engineer, Bureau of Power
J. D. Hebson, Engineer, Bureau of Power
Herbert R. Rinder, Engineer, Bureau of Power
Elmer C. Ilker, Engineer, Bureau of Power
Harold H. Krefft, Engineer, Bureau of Power

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[6] Replaced E. L. Lindseth.

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CONTENTS—Continued

CONTENTS—Continued

SUMMARY

The East Central Region, with a population of about 32 million or 15% of the national total, encompasses approximately 7% of the land area of the contiguous United States and utilizes about 17% of the nation's electric energy. The region, as shown on the map included in the Preface, encompasses all of five states, together with portions of four additional states. It extends from the southern and eastern shores of Lake Michigan and the Illinois-Indiana state line on the west to western Pennsylvania and western Maryland on the east, and from the Lower Peninsula of Michigan and Canada on the north to southern Kentucky and the borders of Tennessee and North Carolina on the south. Classified as Region II by the Federal Power Commission, it includes seven of the 48 FPC power supply areas in the United States.

The non-coincident peak load of the East Central Region for 1965 was 31,000 megawatts (MW) and the electric energy requirements were 180 billion kilowatthours (kWh). The expected non-coincident peak demand will reach about 44,000 MW by 1970 with total energy requirements of approximately 252 billion kWh. By the year 1990, the projected values of demand and energy requirements are expected to be approximately 146,000 MW and 857 billion kWh, respectively. This represents an average annual compound growth rate of 6.3%. In view of the growth of both summer and winter seasonal loads and the already heavy component of industrial load in the region, no significant change in the present relatively high annual load factor of approximately 66% is being projected. The present break-down of consumer usage by major categories of load is 26% for rural and residential, 16% for commercial, 54% for industrial and 4% for all other usage. Again, no significant change in these values is foreseen at this time.

An analysis of load characteristics on a daily, monthly and annual basis shows minimal diversity among the principal power suppliers, producing approximately 95% of all energy requirements in the region. Little, if any, change in this regard is anticipated in the future. At present, both the summer and winter coincident peak demands in the region are very nearly equal. Future seasonal trends in peak demand are difficult to determine in view of the composition and characteristics of the region. There is some evidence, however, that the historical winter peaking characteristic may be tending toward a summer peaking situation.

The East Central Region encompasses a major portion of the Appalachian coal resources. For this reason, coal from within the region historically has provided the vast bulk of raw energy for utility purposes. In 1970 coal will supply about 97% of all electric energy requirements in the region. The anticipated continuing major role of coal as an energy source for electric generation is demonstrated by the fact that even though nuclear power is expected to grow appreciably during the 1970–1990 period, approximately 50% of all electric energy requirements within the region are projected to be supplied by coal-fired plants in 1990. While the percentage contribution of coal to the region's energy requirements will have been significantly reduced during this period, electric energy production from coal-fired plants will have almost doubled between now and 1990. Other energy sources, such as oil, gas and hydro, are expected to continue to play minimal roles in electric power generation.

Since less than 25% of the coal reserves in the East Central Region are of the low-sulfur type (1% or less), since these reserves are relatively concentrated geographically in southeastern Virginia, southern West Virginia and eastern Kentucky, and since they are and will continue to be in high demand by the metallurgical industry, the bulk of the fuel for future coal-fired plants in the region will be of higher sulfur content. With this in mind, the use of tall stacks of 800 to 1,200 feet in height to give better flue gas dispersal has been projected in many instances. Also, since there are, at present, no effective methods of sulfur dioxide removal, tall stacks will continue to provide an interim solution to the achievement of low ground-level sulfur dioxide concentrations. Aware of the need to pursue the development of satisfactory sulfur dioxide removal

techniques, the utilities in the region are undertaking, in cooperation with others in the power industry, a continuing program of research. Such techniques, when developed, will inevitably add to the costs of power supply facilities and thus to the cost of electric energy to the consumer.

To meet the power demands of 1990 it is anticipated that at least 130,000 MW of new generating capacity will be constructed in the East Central Region. These additions, together with existing generation and allowing for retirements, will result in an overall generating capability in the region of about 180,000 MW in 1990 to meet a load of approximately 146,000 MW. Current projections show that most of these generating units will be of increasingly larger size, ranging up to 1,500 MW by 1980 and possibly 2,500 MW by 1990. The effect of this trend to larger sized units to achieve increasing economies of scale will be to radically change the composition of unit size in the region from a mix in 1970 where about 70% of the total installed capacity is in units of 300 MW or smaller size to a distribution of sizes in 1990 where almost 50% of all capacity installed is expected to be in unit sizes of 1,000 MW or larger.

To meet the transmission needs of the region, the already extensively developed extra-high-voltage (EHV) network will have been expanded from a total of about 6,000 miles of transmission line in 1970 to approximately 17,000 miles of 345-kV, 500-kV and 765-kV line by 1990. The latter voltage alone is projected by 1990 to account for almost 25% of all EHV facilities. Extensive additional internal interconnection is projected by the utilities supplying the East Central Region together with reinforced interconnections, many at EHV, to contiguous regions.

Of the 401 identifiable utility entities in the East Central Region, 22 systems, based on available 1965 data, experienced loads of 100 MW or greater, while 307 systems experienced loads of 12 MW or less. The former comprised eighteen investor-owned, one cooperatively owned, and three municipally owned systems. (Since that time Buckeye Power, Inc., an organization of 27 Ohio rural cooperatives with self-owned generation, has come into this category.) Of the 401 electric systems, only 27 representing about 1.2% of the generating capacity in the region, were not interconnected with other systems in 1967.

The investor-owned segment of the power industry in the region comprises four holding companies (two of which are in power pools), four power pools, three unaffiliated operating utilities, and the Ohio Valley Electric Corporation (OVEC), a wholly owned subsidiary of power companies within the region organized to supply the Atomic Energy Commission's gaseous diffusion plant near Portsmouth, Ohio. The member systems of these investor-owned groupings, together with the East Kentucky RECC, in turn, are participants in the East Central Area Reliability (ECAR) Agreement, one of several regional councils in the United States established to augment and assure reliability of bulk power supply. In addition to the power supply groupings described above, Kentucky Utilities Company and East Kentucky RECC, by virtue of their extensive interconnection with each other, operate under a joint agreement.

Responsibility for assurance of reliability and adequacy of bulk power supply in the East Central Region rests first and foremost within the individual power systems, power pools and multi-system planning groups. The net result of these efforts is then reviewed and assessed by ECAR for their overall impact on bulk power supply within and, in turn, outside the region. The latter is achieved through either interregional agreements between ECAR and other contiguous coordinating councils or through liaison and other arrangements among utilities along the boundaries of the East Central Region with other regions.

CHAPTER I

GENERAL DESCRIPTION OF THE EAST CENTRAL REGION

The East Central Region extends over an area including all or portions of nine states. This includes all of Ohio and Indiana, Michigan's lower peninsula, all but a small portion of the states of West Virginia and Kentucky, significant parts of Pennsylvania, Maryland and Virginia, and a small area in and around Kingsport, Tennessee. Exhibit I.1 shows this region in relation to other regions comprising the continental United States.

More than two-thirds of the 32 million people who inhabit the East Central Region live in urban areas, the remainder in rural—both farm and nonfarm. In spite of the above-average population density of the region and its reputation as an industrially oriented area, agriculture and agriculture-related business constitute an important segment of its economy. While the region encompasses less than 7% of the total land area of the contiguous United States, its farms produce over 10% of the nation's farm products, based on value of products sold. Its farms are considerably smaller than elsewhere in the nation, and are cultivated more intensively.

All sections of the region are rich in mineral resources, ranging from coal and petroleum to stone and gravel. The availability of these resources and of navigable waterways led to the early settlement of the region and its ultimate development into a leading industrial area.

Taken as a whole, the region realizes most of its wealth from manufacturing and leads the nation in the production of steel and related products, automotive products, and rubber and plastics. Its other manufacturers cover a wide range of diversified products.

Based on value added by manufacture, more than 20% of the nation's manufactured products come from this region, and about 20% of the nation's manufactured exports. Expenditures for new plant and equipment in the last 15 years indicate that the region's importance as an industrial center is increasing. During that period, annual expenditures for new plant and equipment in the East Central Region have ranged from 20% to 27% of the national total.

While the East Central Region includes some economically depressed sections, notably in the Appalachian areas of Ohio, West Virginia and Kentucky, residents of the states of Michigan, Indiana, Ohio and Maryland are in the upper third among all states in the nation in per capita income.

Perhaps one of the greatest contributing factors to the region's industrial progress has been its water resources—namely, the Great Lakes and the Ohio River, both as a means of transportation and as a source of processing water. In spite of expanded land transportation facilities, traffic on the Ohio River and the Great Lakes has increased substantially.

The opening of the St. Lawrence Seaway has made seaports available that are tied to all major manufacturing sections of the East Central Region by an extensive highway system. The Seaway also has helped stimulate a developing megalopolis extending from Pittsburgh on the east to Chicago and Milwaukee on the west, with a spur extending north to Detroit.

Population projections for the region between now and 1985 indicate that its growth as a whole will be somewhat below the average for the nation. However, the section between Pittsburgh and Chicago is expected to be well above the average in population growth and well on the way toward becoming a continuous city.

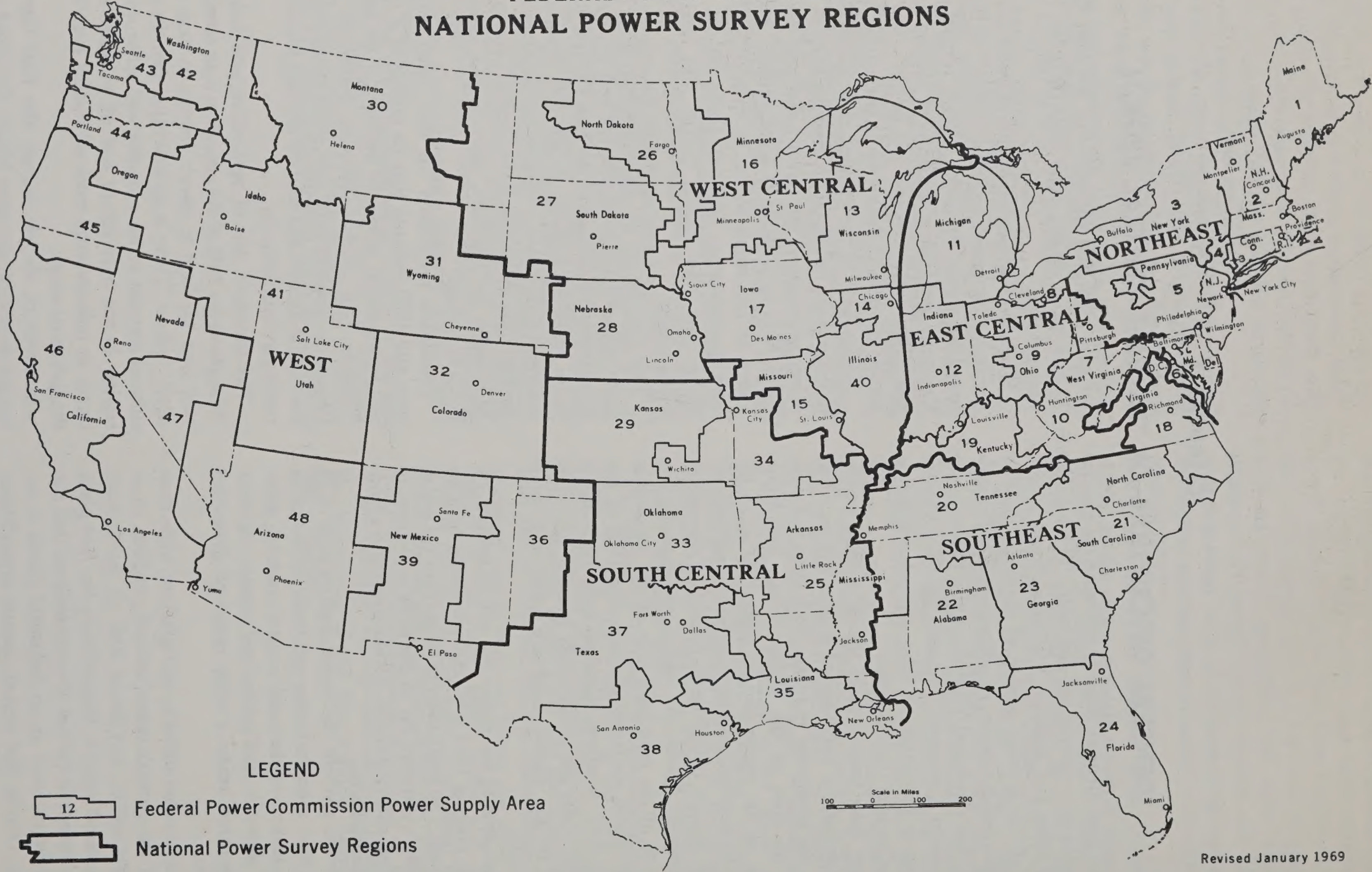
The fortunate mix of agriculture and industry throughout the bulk of the area gives it an economic base that has kept it above average in most economic indices. There is no indication that the agricultural segment of the economy will suffer serious erosion in the near future and all evidence continues to indicate even more substantial growth in the industrial sector.

In terms of electric energy, the East Central Region is one of the most highly developed and

EXHIBIT I.1

FEDERAL POWER COMMISSION

NATIONAL POWER SURVEY REGIONS



Revised January 1969

significant areas of the United States. While it covers less than 7% of the land area, it utilizes about 17% of the nation's electric energy. It contains some of the country's most noted steam-electric plants which are well distributed throughout the area. This generation is tied into a well integrated and heavily interconnected transmission grid, operating at voltages ranging from 120 kV to 765 kV. This network is also heavily interconnected to systems outside the region, and includes major ties to Illinois, Tennessee, North Carolina, and Ontario (Canada), as well as to other systems in Virginia, Kentucky, Maryland, and Pennsylvania.

The size and intensive development of the power systems in the East Central Region are sharply brought out by a comparison of its electric energy consumption with that of five major countries of Western Europe, namely, the United Kingdom, Sweden, West Germany, France, and Italy. The East Central Region has a population of 32 million versus approximately 225 million for these countries, a ratio of 1 to 7. The 1967 total electric energy production in the region was 215 billion kilowatthours compared with 525 billion kilowatthours for these same countries, a ratio of 1 to 2.4. Thus, the East Central Region has a per capita energy ratio of almost 3 to 1 compared with that of five major countries of Western Europe combined. This comparison of the region with one of the most technologically advanced and highly industrialized areas of the world provides additional perspective of the area's characteristics.

CHAPTER II

FUTURE POWER REQUIREMENTS

Introduction

A prerequisite to any discussion of future patterns of power supply in the East Central Region is a determination of probable trends in electric power consumption. The purpose of this chapter is to analyze and project the power requirements of the region for the 1970–1990 period. As such, it provides a basis for the future planning and operation of the power systems which serve the region. The forecast of possible future generation and transmission expansion patterns described in Chapter X of this report is based in large measure on the power requirements statistics presented in this chapter. Also, these statistics provide a basis for the comparison of developments with other regions of the country.

The scope and form of the power requirements projections, described below, are consistent with those prepared by other regions. Peak demand, energy for load, and load factor are presented as experienced in 1965 and as envisioned for every fifth year, namely, 1970, 1975, 1980, 1985 and 1990. The energy for load is classified by customer groups, with the AEC Portsmouth area load listed as a separate category. Seasonal characteristics are discussed and area load diversity is analyzed. Growth patterns within the region are illustrated. As is customary in such statistical analyses, most of the load data are grouped by PSA's (Power Supply Areas established by the Federal Power Commission).

As previously indicated, the East Central Region consists of all or large portions of the states of Michigan, Indiana, Ohio, Kentucky, and West Virginia, together with parts of Pennsylvania, Maryland, and Virginia, and a small area in and around Kingsport, Tennessee. This entire area is indicated as Region II on the map of the National Power Survey Regions (Exhibit I.1).

In terms of Power Supply Areas, the East Central Region includes PSA numbers 7, 8, 9, 10, 11, 12, and 19. These PSA's are used as the basis for describing the electric power requirements of the region.

The load projection data presented in this chapter were developed by the East Central Regional Advisory Committee's Task Force on Load Projection. All of the exhibits and most of the discussion contained in the Task Force report, entitled "Load Projection 1970 Thru 1990," are included. The Task Force was assisted in its work by the staffs of the New York, Chicago, and Atlanta FPC Regional Offices.

This chapter first presents a brief discussion of the methods used to project load and energy requirements. This is followed by a presentation of load, energy, and load factor data for each PSA through 1990. These energy requirements are then classified according to customer groups. Daily and seasonal load characteristics are discussed, and data are presented to indicate annual, monthly, and daily load diversity within the East Central Region. Finally, this chapter presents and discusses load growth patterns and principal load centers of the region.

Load Projection Methods

Practically every type of activity in the electric power industry necessitates the projection of load requirements. The daily operation of each system or group of systems requires short-term forecasts, based heavily on weather, seasonal variations, and specific industrial activity to schedule economically and reliably the hourly loading of generating facilities. Such information likewise is essential in scheduling maintenance outages of generation and transmission facilities. Forecasts of medium range are required for planning additions in generation and transmission, while projections of peak de-

mands 20 years or more into the future are helpful for the development of long-range system patterns. The planning of the system on a long-range basis is essential to assure optimum short-term development of system facilities and to allow sufficient time to conduct research and develop new equipment to meet future needs.

In addition to the time dimension in load forecasting there is the space dimension, that is, a projection of the evolving geographic pattern of future power requirements.

The importance of accuracy in the time and space dimensions of load projection depends, of course, on the use of the data. Thus, studies within a specific system for the purpose of establishing the timing of future generating plant additions are based mainly on the annual peak load projections for the total system, as well as the projected hourly, daily and seasonal characteristics of the total load. Studies of local transmission and distribution system developments need to be based on where the load must be served as well as its timing, and require the projection of annual peak loads at specific substations. Studies of bulk power transmission, particularly at extra-high voltages, require the resultant annual peak loads at principal supply substations as well as a knowledge of the generation sources, oftentimes for extensive areas of the interconnected network, and thus must consider the time as well as the space dimension of future power requirements.

Long-term estimates for any area under study show the normal trend of power requirements that may be expected on the basis of the area's natural resources, its ability to attract and support economic growth, and a reasonable rate of development. Generally, no attempt is made to predict economic cycles; the load estimates at any period in time may be either above or below the actual requirements, depending on economic conditions then prevailing. Although the loads for a given year may be reached either a few years before or later than estimated, such studies show the probable size of the market which will exist.

In forecasting long-term power requirements, it is customary to make detailed local area estimates as well as overall system load estimates. Estimates of overall requirements generally are based on the trend established over the past 10 to 15 years. The trend, determined by means of curve-fitting techniques, is extended through the period under study. Estimates based on judgment and knowledge of the region are used to modify the projected trend to account for deviations due to changing economic conditions, changing area population, or other factors influencing electric load growth.

A number of interrelated factors have been found valuable in forecasting electric power requirements. These factors, some of which are based on analyses of past data, have shown varying degrees of correlation with projected results.

A widely used factor in forecasting future electric energy requirements is population, which is one of the most readily available and most reliable types of statistical information. Population size has been found to have its most significant influence on the amount of residential electric energy required. Based on past history, good correlation has been established between the number and size of households and the amount of electric energy consumed. Such correlations, however, can be significantly altered by the development and marketing of new applications such as electric heating.

Population size is also related to commercial sales, but probably to a lesser degree than to residential sales. Commercial sales are more directly affected by the general trend of business conditions and by the degree of acceptance of new electric energy applications, such as lighting, commercial cooking and air conditioning. In recent years the growth of air conditioning has become an important segment of commercial load during the summer months. In many urban areas the impact of this type of load growth may be less pronounced in the future as the air conditioning market approaches its saturation level. New opportunities for increased commercial sales are developing, however. Heating with light, an overall emphasis on higher lighting levels, and all-electric office buildings are making new contributions.

The level of activity of the economy, the type of industry served, and technological changes in industrial processes are primary factors in determining industrial requirements. Such indicators as the Gross National Product and the Federal Reserve Board Index of Manufactures are helpful in providing a general indication of economic activity and its possible effect on energy requirements. Consideration also must be given the projected activity of

high energy use industries, the availability of industrial sites, the type of industry likely to be attracted to an area, and specific expansion plans of existing major energy consumers.

The development of new electric energy-consuming processes has a major impact on industrial requirements. Technological innovation and the outlook for further automation of the industries within an area has been, and will continue to be, an important factor in any forecast of industrial loads. Although much of the technology that will be developed in the next 25 years is impossible to predict, a great deal of work is being done on technological forecasting and some significant changes in industrial trends can be seen. For example, according to a recent study by Battelle Memorial Institute, a major increase can be expected in the use of electric furnaces by the steel industry. In 1967 approximately 15 percent of the steel-making capacity of the United States was in electric furnaces. By 1990 it is estimated that electric furnaces will produce nearly half of the steel output.

The natural resources, including water supply and geographical features of an area, can have a pronounced effect on industrial, commercial, and residential load developments. Also important are existing and future transportation facilities.

The need for more accurate and more detailed information on future electric power requirements has been pointed up by the current national emphasis on power system reliability, coupled with growing activities in long-range inter-system planning and coordination. Another important factor in this connection has been the increasing lead time requirements for the planning, manufacturing and construction of major power system facilities, together with the extensive time required for securing regulatory approvals in nuclear and hydro licensing This has placed a renewed emphasis on the methods used for providing this load information. Thus, there is increasing effort towards quantifying load forecasting techniques and developing methods which are much more sophisticated than those based primarily on an "educated extrapolation" of past performance and growth trends. Recent developments in the use of quantitative methods and analytic tools have made some advances and are being pursued further.

A danger inherent in overly quantitative load forecasting techniques is that they may tend to become pseudoscientific, with various questionable basic assumptions hidden by numerical detail and manipulation. The air of certainty often conveyed is seldom well-founded and can hinder rather than aid the user's judgment.

A good forecasting procedure can be quantitative in nature but must be flexible enough to allow evaluation of the effects of various assumptions and to permit the use of judgment and imagination. The load forecaster must weight carefully all data, factors and speculations in light of his best judgment, and point up the importance and effects of the various assumptions on the projected power requirements.

Similarly, any system development plans based on the projected load data must be evaluated in light of possible variations in actual loads, the economic consequences of such variations, and their overall effect on service reliability.

Against the background of these many considerations, the Task Force did not believe it realistic to carry out its own independent analysis of probable future trends in load and energy requirements in the East Central Region. Instead, it decided to pool the independent judgments of the various utilities concerned, thereby reflecting their diversified methods and assumptions. For this purpose the Task Force sent a questionnaire to all of the major utilities, municipals, and power supply cooperatives within the East Central Region asking for their projections in peak demand and energy through the year 1990. These data were requested by May 1, 1967. The questionnaire also asked for these projections in five different categories of retail consumption.

Load projections also were obtained from the appropriate Federal Power Commission Regional Offices, namely, Chicago, New York and Atlanta. This information together with the responses to the above questionnaire as well as data from other sources (such as EEI reports), provided the basis for the projections which follow.

Although per capita use, population projections, Gross National Product or other forecasting methods were not utilized directly by the Task Force in making the projections, these factors undoubtedly were utilized in varying degrees by the respondents to the Task Force's questionnaire and are, therefore, incorporated into the projections determined

EXHIBIT II.1

East Central Region Future Power Requirements

	(1,000 kW)	(1,000,000 kWh)				
	1965 [1]	1970	1975	1980	1985	1990
PSA–7:						
Peak Demand	3, 948	[5] 5, 140	[5] 6, 660	[5] 8, 640	[5] 11, 250	[5] 14, 600
Energy for Load	23, 885	31, 100	40, 400	52, 600	68, 400	88, 900
Load Factor %	69. 1	69. 1	69. 2	69. 3	69. 4	69. 5
PSA–8:						
Peak Demand [2]	2, 002	2, 590	3, 450	4, 590	6, 110	8, 140
Energy for Load	11, 574	15, 400	20, 530	27, 350	36, 400	48, 500
Load Factor %	66. 0	68. 0	68. 0	68. 0	68. 0	68. 0
PSA–9: [3]						
Peak Demand	6, 625	9, 750	13, 310	18, 220	24, 980	34, 310
Energy for Load	40, 925	59, 300	81, 000	110, 900	152, 400	209, 800
Load Factor %	70. 5	69. 4	69. 5	69. 5	69. 6	69. 8
PSA–10:						
Peak Demand	2, 273	3, 020	4, 010	5, 310	7, 080	9, 410
Energy for Load	13, 770	18, 300	24, 400	32, 500	43, 300	57, 700
Load Factor %	69. 2	69. 2	69. 5	69. 7	69. 8	70. 0
PSA–11:						
Peak Demand	7, 145	9, 900	13, 250	17, 600	23, 400	30, 600
Energy for Load	39, 807	56, 210	75, 900	102, 000	137, 000	181, 000
Load Factor %	63. 6	64. 8	65. 4	66. 2	66. 8	67. 5
PSA–12:						
Peak Demand [2]	8, 149	11, 500	16, 000	22, 000	30, 000	41, 400
Energy for Load	45, 640	63, 120	88, 900	123, 000	169, 000	233, 200
Load Factor %	63. 9	62. 7	63. 4	63. 8	64. 3	64. 3
PSA–19:						
Peak Demand [2]	964	1, 770	2, 470	3, 470	5, 280	7, 490
Energy for Load	4, 897	8, 770	13, 080	18, 080	27, 080	38, 080
Load Factor %	58. 0	56. 6	60. 5	59. 5	58. 5	58. 0
Total East Central: [3]						
Peak Demand [4]	31, 106	43, 670	59, 150	79, 830	108, 100	145, 950
Energy for Load	180, 498	252, 200	344, 210	466, 430	633, 580	857, 180
Load Factor	66. 2	65. 9	66. 4	66. 7	66. 9	67. 0

6.3%

[1] Actual usage.
[2] Summer peak.
[3] Does not include the AEC load.
[4] Non-coincident yearly peak.
[5] The most recent studies indicate that estimates of peak demand and energy in PSA–7 should be increased to 5,570 MW and 33,200 million kWh for 1970, 7,510 and 46,800 for 1975, 9,730 and 60,400 for 1980, 12,700 and 78,200 for 1985, and 16,600 MW and 102,000 million kWh for 1990.

through the summation of the individual responses. After preliminary projections were completed, the utilities were advised of these proposed projections and basic agreement was reached in each PSA as described below.

Load Forecasts by Power Supply Areas

(See Exhibit I.1 for location of the PSA's.)

PSA–7—The response to the questionnaire covered 98% of this area and incorporates a compound growth rate of 5.3%. (Subsequent data indicate that this figure should be increased to 6.0% to reflect new power requirements.)

PSA–8—The response to the questionnaire covered 98% of this area and incorporates a 5.9% growth rate.

PSA–9—The highly specialized load of the Atomic Energy Commission (AEC)is located within this area and, because of its unique characteristics, the Task Force elected to present this load as a special

entry. The questionnaire response covered 95% of the area. The Task Force's recommendation incorporates a growth rate of 6.7%, excluding AEC.

PSA–10—The response to the questionnaire represented about 98% of this area and incorporates a growth rate of 5.9%.

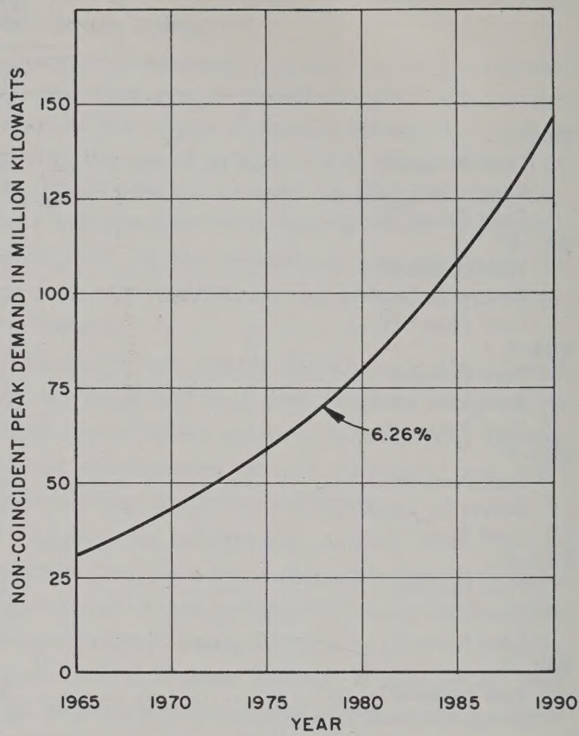
PSA–11—The response to the questionnaire represented about 98.5% of the load served in this area and indicated a growth rate somewhat less than that in neighboring power supply areas. Examination of past trend data for PSA–11 and a review of growth rates in adjacent areas resulted in the Task Force's development of a preliminary load growth rate of 6% per year. After a further survey of the utilities in this area, approval was received for the modified estimate and an average 6% growth was adopted by the Task Force.

PSA–12—The response to the questionnaire represented approximately 85% of this area and the Task Force recommended a compound growth rate of 6.5%.

PSA–19—The response to the questionnaire represented 96% of this area. Examination of past growth rates and knowledge of the area resulted in the Task Force recommending a compound growth rate of 7.6%.

EXHIBIT II.2

EAST CENTRAL REGION
NON-COINCIDENT PEAK DEMAND



Annual Power and Energy Projection

The projected peak demands, energy for load, and load factors for the East Central Region through 1990, as well as the actual usage in 1965, are indicated in Exhibit II.1. These data, listed by PSA's, do not include the AEC's gaseous diffusion plant near Portsmouth, Ohio (PSA–9). The total peak demand for each time period is the sum of the peak demands for all PSA's, and, therefore, is the noncoincident peak demand for the region.

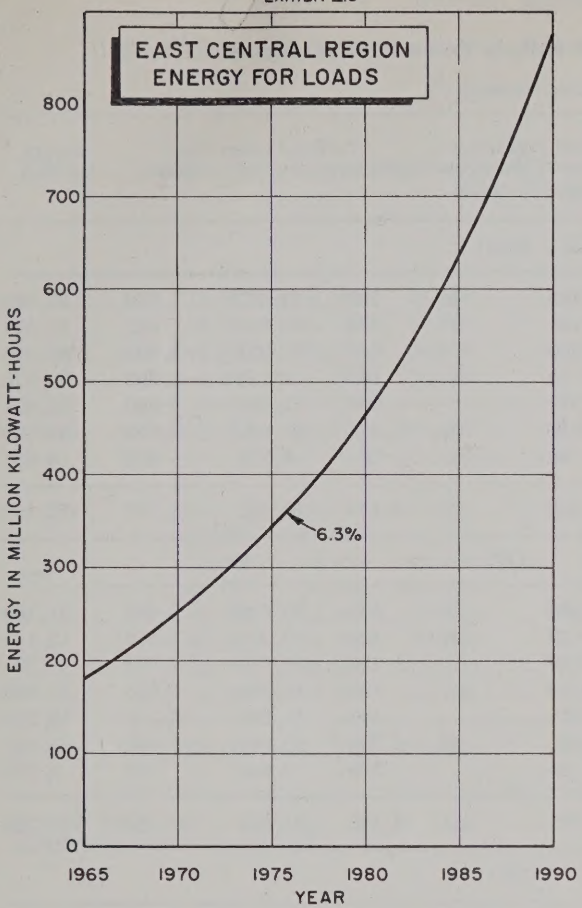
Exhibit II.1 shows an increase in peak demand from 1970 to 1980 of 1.83 times, an increase from 1980 to 1990 also of 1.83 times, and an overall 20-year increase of 3.34 times. The 20-year projection of loads for the region results in an indicated growth rate in demand of 6.26% compounded, as shown by Exhibit II.2. If the AEC load were included, its relative size and expected growth would have relatively little effect on the indicated percent compound growth rate.

Also, Exhibit II.1 shows an increase in energy use from 1970 to 1980 of 1.85 times, with a further increase of 1.84 by 1990. This represents a growth rate of 6.3% annually, as indicated by Exhibit II.3. The load factor for the region is projected to improve slightly from 65.9% in 1970 to 66.4% in 1975 and further to 67% in 1990.

Information concerning the Atomic Energy Commission's gaseous diffusion plant near Portsmouth, Ohio, was received from the New York Office of the Federal Power Commission and includes an estimate of probable future power requirements. This plant, which basically was designed for a peak load level of 1,800 MW, started full production in 1955 with a peak load of 2,031 MW, reached maximum production in 1956 with a peak load of 2,142 MW, and had been operating above 1,800 MW until 1965. The 1965 and future load data, listed in Exhibit II.4, indicates that the AEC plant will resume full operation by about 1975 and its demand will increase to a maximum of 2,350 MW by 1980, remaining at this magnitude thereafter.

The Task Force felt that this load should be shown as a separate item rather than be included as a normal utility load in PSA–9, thus facilitating

EXHIBIT II.3



a more meaningful comparison of load data among PSA's and among regions.

Classification of Energy Requirements

The estimated future energy requirements of the East Central Region are classified by customer groups in Exhibit II.5. Data are presented each fifth year from 1965 through 1990 for each PSA. Again, the AEC Portsmouth area load is excluded from PSA–9.

Of the total energy consumption in 1970, 26% is for rural and residential use, 16% for commercial, and 54% for industrial use; the remaining 4% being for all other use including street lighting and electric transportation. To the total consumption of approximately 232 billion kilowatthours are added some 21 billion kWh for losses, which account for 8.2% of the resulting energy for load. This loss figure is an approximate estimate and is not based on any precise calculation.

The 1990 estimated energy requirements indicate approximately the same share of consumption among the various classifications as the 1970 figures. Again 26% of total consumption is for rural and residential use, 18% for commercial, and 53% for industrial use. The remainder is 3% and assumes no growth for electric transportation. If studies currently in progress should result in the adoption of new railroad electrification and the expansion of rapid transit systems, the latter projection could well be in error. The total energy for load in 1990 is estimated to be about 857 billion kWh, of which 8.1% is for losses. The percentage loss is necessarily the result of an arithmetic extrapolation and does not represent a precise determination.

The range of rural and residential consumption among the PSA's for 1970 is 23% to 35% with PSA's 7, 8 and 9 at the lowest and PSA–19 at the highest level. Commercial consumption ranges from 12% in PSA–9 to 19% in PSA–11. Industrial consumption is highest at 62% in the Ohio River Valley (PSA–9), followed by PSA–10 at 59% and PSA–7 at 56%, with the lowest being PSA–19 at 44%.

EXHIBIT II.4

Power Supply Area 9—Atomic Energy Commission's Past and Estimated Future Power Requirements

Year	Sales to AEC (million kWh)	Losses (million kWh)	Energy for system (million kWh)	Peak demand (MW)
1965.......	10, 510	318	10, 828	1, 207
1970.......	4, 190	110	4, 300	500
1975.......	15, 090	390	15, 480	1, 800
1980.......	19, 700	510	20, 210	2, 350
1985.......	19, 700	510	20, 210	2, 350
1990.......	19, 700	510	20, 210	2, 350

Load Diversity Within the East Central Area

Possible differences in load shape, i.e., the variation of load with time, that may exist from system to system within the East Central Region were not examined by either the FPC or by the Load Projection Task Force. However, an analysis has been made of the diversity which has existed among the 19 systems comprising the membership of the East Central Area Reliability Coordination Agreement (ECAR). (Refer to Chapter VII for the systems comprising ECAR.) This study was made for the

EXHIBIT II.5

East Central Region—Estimated Future Power Requirements

[Millions of kilowatt-hours]

PSA	Rural and residential	Commercial	Industrial	Street and highway lighting	Electric transportation	All other	Total consumption	Losses	Energy for load
1965 [1]									
7	5, 222	3, 948	12, 517	148	60	182	22, 077	1, 808	23, 885
8	2, 499	2, 057	5, 651	143	27	342	10, 719	855	11, 574
9 [2]	8, 743	4, 484	23, 517	260	3	830	37, 837	3, 088	40, 925
10	3, 092	1, 510	7, 371	55	....	143	12, 171	1, 599	13, 770
11	10, 237	6, 760	17, 585	372	....	1, 003	35, 957	3, 850	39, 807
12	12, 806	6, 777	20, 111	414	46	1, 528	41, 682	3, 958	45, 640
19	1, 879	716	1, 349	48	....	286	4, 278	619	4, 897
Total	44, 478	26, 252	88, 101	1, 440	136	4, 314	164, 721	15, 777	180, 498
1970									
7	6, 900	5, 230	16, 000	180	50	250	28, 610	2, 490	31, 100
8	3, 360	2, 810	7, 450	170	30	420	14, 240	1, 160	15, 400
9 [2]	12, 700	6, 400	34, 200	330	....	1, 120	54, 750	4, 550	59, 300
10	4, 200	2, 180	9, 730	80	....	199	16, 380	1, 920	18, 300
11	15, 000	9, 710	24, 500	515	....	1, 300	51, 025	5, 185	56, 210
12	16, 190	9, 560	29, 730	450	30	2, 700	58, 660	4, 460	63, 120
19	2, 842	1, 183	3, 545	60	....	370	8, 000	770	8, 770
Total	61, 192	37, 073	125, 155	1, 785	110	6, 350	231, 665	20, 535	252, 200
1975									
7	9, 150	7, 030	20, 330	220	100	340	37, 170	3, 230	40, 400
8	4, 520	3, 860	9, 830	210	30	530	18, 980	1, 550	20, 530
9 [2]	17, 200	9, 100	46, 400	420	....	1, 600	74, 720	6, 280	81, 000
10	5, 800	3, 050	12, 650	100	....	250	21, 850	2, 550	24, 400
11	19, 980	13, 400	33, 250	710	....	1, 700	69, 040	6, 860	75, 900
12	21, 300	13, 400	42, 900	570	30	3, 600	81, 800	7, 100	88, 900
19	4, 057	1, 768	5, 576	87	....	444	11, 932	1, 148	13, 080
Total	82, 007	51, 608	170, 936	2, 317	160	8, 464	315, 492	28, 718	344, 210
1980									
7	12, 120	9, 460	25, 910	280	150	470	48, 390	4, 210	52, 600
8	6, 080	5, 290	12, 960	260	30	660	25, 280	2, 070	27, 350
9 [2]	23, 500	13, 100	62, 870	520	....	2, 250	102, 240	8, 660	110, 900
10	8, 000	4, 350	16, 330	140	....	330	29, 150	3, 350	32, 500
11	26, 950	18, 650	44, 600	870	....	2, 180	93, 250	8, 750	102, 000
12	29, 500	19, 700	58, 300	770	30	4, 900	113, 200	9, 800	123, 000
19	5, 755	2, 552	7, 429	117	....	557	16, 410	1, 670	18, 080
Total	111, 905	73, 102	228, 399	2, 957	210	11, 347	427, 920	38, 510	466, 430
1985									
7	16, 070	12, 710	33, 010	350	150	640	62, 930	5, 470	68, 400
8	8, 170	7, 250	17, 090	310	30	810	33, 660	2, 740	36, 400
9 [2]	32, 200	18, 700	85, 700	660	....	3, 150	140, 410	11, 990	152, 400

See footnotes at end of table.

EXHIBIT II.5—Continued

East Central Region—Estimated Future Power Requirements—Continued

[Millions of Kilowatt-hours]

PSA	Rural and residential	Commercial	Industrial	Street and highway lighting	Electric transportation	All other	Total consumption	Losses	Energy for load
				1985—Continued					
10	11, 000	6, 200	21, 050	200	....	430	38, 880	4, 420	43, 300
11	35, 700	25, 680	60, 300	1, 085	....	2, 785	125, 550	11, 450	137, 000
12	42, 300	27, 000	78, 500	870	30	6, 800	155, 500	13, 500	169, 000
19	8, 545	4, 182	10, 849	167	....	726	24, 469	2, 611	27, 080
Total	153, 985	101, 722	306, 499	3, 642	210	15, 341	581, 399	52, 181	633, 580
				1990					
7	21, 300	17, 090	41, 950	430	150	870	81, 790	7, 110	88, 900
8	10, 980	9, 930	22, 530	380	30	1, 000	44, 850	3, 650	48, 500
9 [2]	44, 000	26, 500	117, 450	820	....	4, 460	193, 230	16, 570	209, 800
10	15, 000	8, 900	27, 150	270	....	560	51, 880	5, 820	57, 700
11	47, 100	35, 000	79, 350	1, 350	....	3, 500	166, 300	14, 700	181, 000
12	58, 500	36, 000	110, 500	1, 170	30	9, 000	215, 200	18, 000	233, 200
19	11, 728	5, 809	15, 685	223	....	874	34, 319	3, 761	38, 080
Total	208, 608	139, 229	414, 615	4, 643	210	20, 264	787, 569	69, 611	857, 180

[1] Actual usage.

[2] Excluding atomic energy load.

5-year period 1962 through 1966 using the computer program developed by the Edison Electric Institute. Figures quoted in this discussion have been taken from the results of that study.

These figures are believed to be quite representative of the entire East Central Region because the 19 ECAR systems supply approximately 95% of the total electric energy requirements of the region. Furthermore, the systems not included in the analysis are believed to have characteristics similar to those of the ECAR systems. Thus they would have negligible effect on the load diversity within the region.

Load diversity is defined as the difference between the sum of the independent peak loads of systems or areas being considered and the coincident peak loads of the combined systems or areas for any specified period of time. This difference is expressed in kilowatts or in percent of the coincident peak load. For example, the daily diversity among a number of systems for each day is the difference between (1) the sum of the independent peak loads of each system regardless of their hour of occurrence, and (2) the sum of the loads of all systems during the hour of maximum coincident demand. In addition to daily diversity, commonly used terms include monthly and annual diversity, the latter often being called seasonal diversity.

Diversity among systems, when sizable and predictable, can be used in various ways to improve economy. Annual diversity, if it can be predicted sufficiently in advance with an adequate degree of accuracy, can help reduce the total installed capacity requirements of the systems involved, provided adequate transmission capability exists. Monthly diversity might be useful for short term coordinated maintenance of generating plant. Daily diversity can contribute to efficient daily operation by permitting the interchange of economy energy.

Annual diversity interchanges historically have taken place between systems in Region II and Region IV. Such transactions have reflected the winter peak load characteristic of some systems in Region II as contrasted with the growing summer

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peak load characteristics of the systems in Illinois. Interchanges of this type may be expected to continue in the future if the respective load patterns permit.

An analysis of load diversity on a daily basis for the 19 ECAR systems shows less than 1 percent for approximately 80% of the total weekdays in the 1962–1966 5-year period and greater than 2% on only 2 such days.

The monthly load diversity, illustrated by Exhibit II.6, was less than 2 percent approximately 80% of the time and it exceeded 3 percent only 2 months during the 5-year study period. The monthly load diversity during the peak load month was always less than 1 percent with a minimum value of about 0.3% occurring in December 1965. The annual load diversity, also indicated by Exhibit II.6, exceeded 2 percent two of the 5 years, ranging from approximately 1.5% in 1963 to 4.2% in 1964, with the coincident peak occurring in December in each of the 5 years. The practically random nature of the annual and monthly load diversities illustrated by Exhibit II.6 points up the difficulty of predicting these values with useful accuracy.

The daily load shape of the region provides some insight regarding the low values of daily diversity within the region as well as the minimal opportu-

EXHIBIT II.6

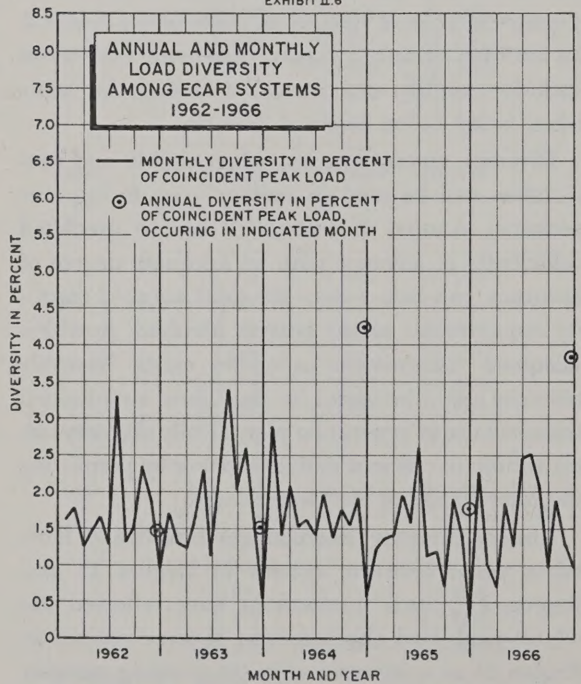


EXHIBIT II.7

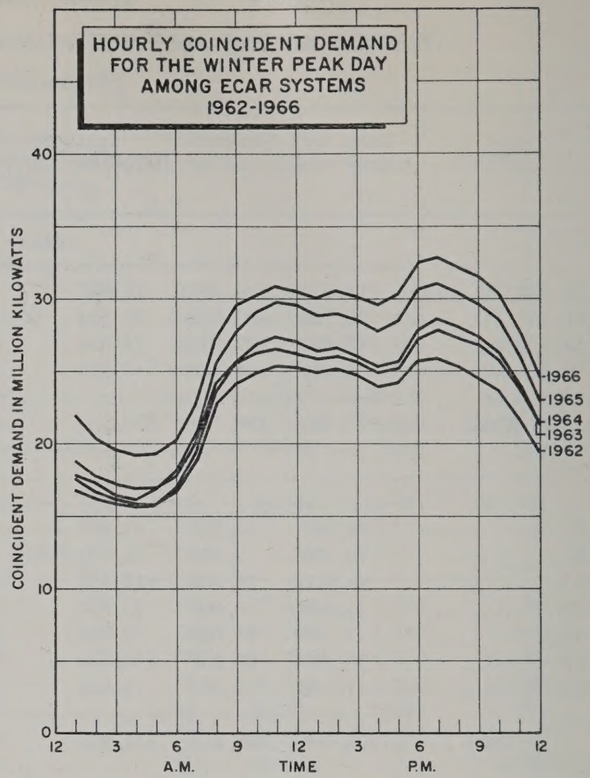
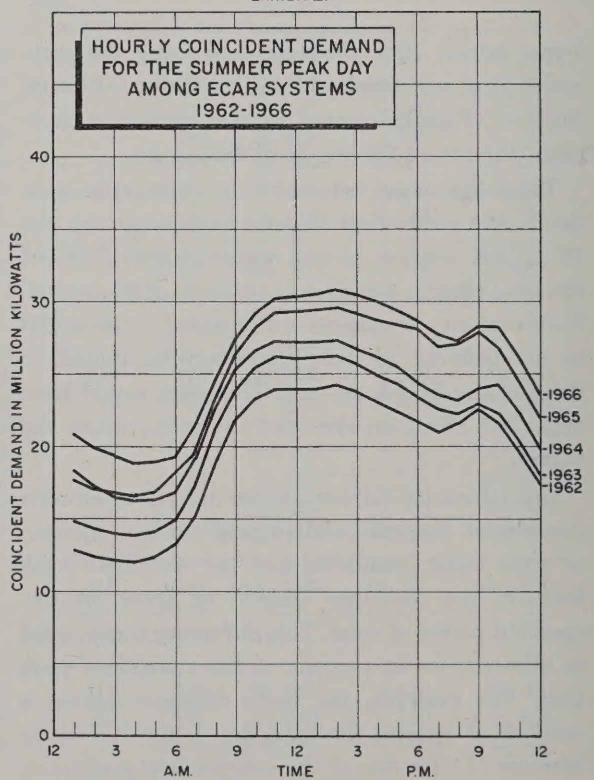


EXHIBIT II.8



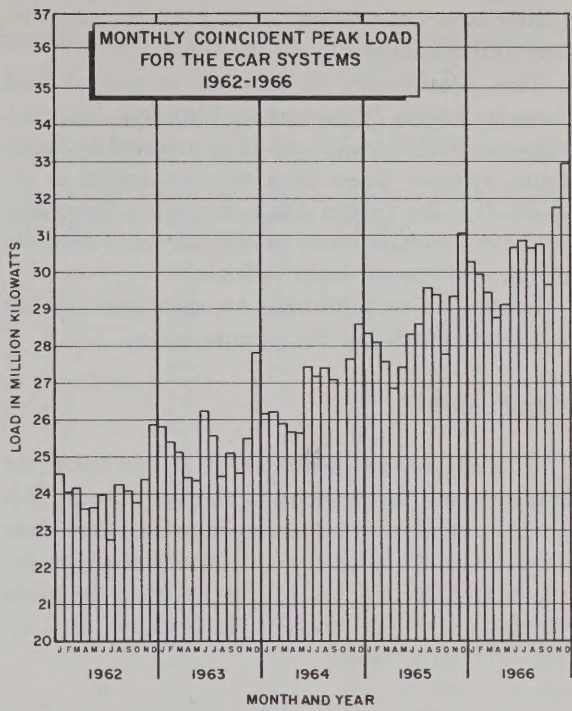
nities for interchange with other regions. Exhibits II.7 and II.8 show the hourly coincident demand versus time for the winter peak day and the summer peak day, respectively, for each of the 5 years 1962–1966. These curves are consistently "flat," particularly during the summer daytime peak hours, showing little load variation over a period of 4 to 8 hours. Since adjacent areas have shown similar load characteristics, there appears to be little, if any, opportunity for daily diversity exchange.

The annual load shape of the region, which contributes to the annual or seasonal diversity, is indicated in Exhibit II.9. This is a plot of the monthly coincident peak loads for the ECAR systems for the 1962–1966 5-year period. The pattern from year to year is not particularly consistent, except that the annual peak for the region has occurred in December for each of these years.

Four of the ECAR systems, excluding the Ohio Valley Electric Corporation (OVEC) which serves the AEC Portsmouth area load, experienced summer peaks in 1962. By 1966 the number had reached nine, and by 1968 many of the remaining winter peaking systems were exhibiting a trend toward becoming summer peaking systems. The coincident annual peak day for the 19 ECAR systems occurred during the summer for the first time in 1968. The summer peak day load exceeded the following winter peak day by slightly more than 1 percent. Preliminary operating data indicate that there was essentially zero diversity for the summer peak hour. Analysis of weather conditions for 1968 indicates that the winter peak could have exceeded the summer peak had the weather conditions experienced during January 1969 occurred during December 1968. It may be noted that this apparent trend toward a summer peak in the East Central Region developed significantly after the compilation of the Load Projection Task Force questionnaire in May 1967 and therefore may appear to be somewhat contradictory to the projections given in the Task Force report. This illustrates the difficulty in projecting seasonal load characteristics.

The sensitivity of power system loads to temperature appears to be increasing, both within the summer and winter periods, and a positive trend toward a composite winter peaking or summer peaking system cannot be ascertained in all cases from present data. Thus, the variable nature of the diversity

EXHIBIT II.9



pattern in terms of both time and amount, as well as the minimal magnitude of the diversity within the region, indicates quite strongly that the area cannot expect to take advantage of diversity when planning its resources. However, it will continue to take full advantage of whatever diversity might become available on a short-term basis.

Principal Load Centers and Growth Patterns

To supplement the overall projections of future power requirements and provide a basis for formulating possible patterns of generation and transmission, each PSA of the East Central Region has been subdivided into general but more localized load areas. Exhibit II.10 lists the annual peak demands experienced by these load areas in 1960 and 1965, and indicates the projected demands for 1970, 1980, and 1990. The total demand for each PSA is the same as indicated in Exhibit II.1 for any given year. These load areas are coded with a map number and are indicated on a map of the region for each of the years 1965, 1970, 1980, and 1990 (Exhibit II.11). To help visualize the growing concentrations of load, the areas are indicated by a circle the size of which is keyed to the size of the peak demand.

These maps and tables have been prepared jointly by representatives of the FPC Regional Offices and members of the Task Force.

The identification of demands in general load areas in Region II is based on historical data contained in FPC Forms 1 and 12 as reported by major utility systems. These data were expanded to include all utility systems within the region. Generally, load areas include larger geographic areas than the community names might indicate.

Generation by industrials for their own use has not been included in the maps or tables.

Conclusion

This chapter has presented in various forms the future power requirements of the East Central Region. In addition to presenting a projection of these requirements through the year 1990, it has included tables and illustrations to help visualize the space dimension or geographic distribution of load throughout the region.

The following conclusions highlight the various sections of this chapter.

1. In developing the future power requirements of the region, the Load Projection Task Force utilized the collective judgment and diversified methods of all major utilities, municipals, and power supply cooperatives within the region by soliciting by questionnaire their estimates of future load growth. Any users of the data presented herein, however, should weigh carefully the effects of possible variations in these load developments.

2. Both the peak demand and energy for the region are envisioned to increase at a compounded annual rate of 6.3%.

3. The East Central Region is very heavily industrialized, with industrial energy consumption averaging 53 to 54% and ranging as high as 62% of total energy consumption in one PSA.

4. Load diversity within the region is insufficient in magnitude and too variable in nature to be used in the long-range planning of system development.

EXHIBIT II.10

East Central Region—Estimated Annual Peak Demands by General Load Areas (Megawatts)

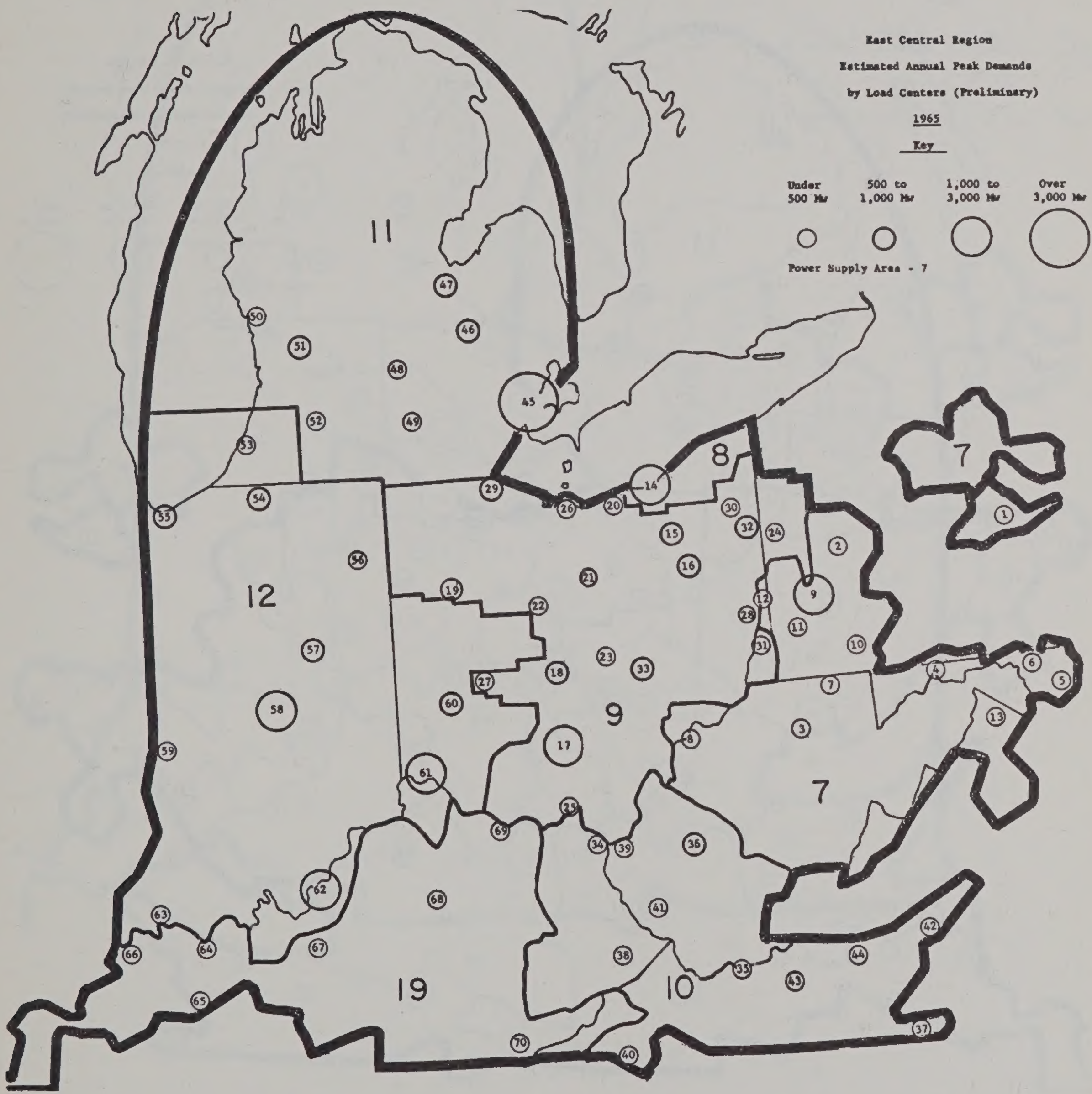
PSA	Map No.	General load areas	1960	1965	1970	1980	1990
7	1	Bellefonte, Pa.	100	145	200	335	560
	2	Butler-Kittanning, Pa.	370	460	605	1, 015	1, 715
	3	Clarksburg, W. Va.	120	175	225	380	640
	4	Cumberland, Md.	85	120	155	260	440
	5	Frederick, Md.	65	100	130	215	365
	6	Hagerstown, Md., Chambersburg, Pa.	140	225	295	500	840
	7	Morgantown, W. Va.	115	170	220	370	625
	8	Parkersburg, W. Va., Marietta, Ohio	105	175	220	370	630
	9	Pittsburgh, Pa.	1, 185	1, 413	1, 840	3, 100	5, 235
	10	Uniontown-Connellsville, Pa.	205	310	395	660	1, 120
	11	Washington-Monessen, Pa.	330	425	555	930	1, 575
	12	Weirton, W. Va.	115	130	170	290	490
	13	Winchester, Va.	60	100	130	215	365
		Total PSA 7	2, 995	3, 948	5, 140	8, 640	14, 600
8	14	Cleveland, Ashtabula	1, 595	2, 002	2, 590	4, 590	8, 140
9	15	Akron, Ohio	435	550	775	1, 480	2, 825
	16	Canton, Alliance, Massillon, Ohio	395	520	730	1, 390	2, 650
	18	Columbus, Ohio	570	770	1, 060	2, 020	3, 850
	19	Lima, Tiffin, Ohio	410	590	810	1, 550	2, 960
	20	Lorain-Elyria, Ohio	145	220	320	610	1, 155
	21	Mansfield, Shelby, Ohio	140	205	285	545	1, 030
	22	Marion, Ohio	75	105	145	280	530
	23	Newark, Ohio	165	230	330	630	1, 195
	24	New Castle, Pa.	140	175	255	490	935
	25	Portsmouth, Ohio	140	220	315	600	1, 145
	26	Sandusky, Norwalk, Ohio	95	135	190	360	695
	27	Springfield, Ohio	75	100	160	270	520
	28	Steubenville, Ohio	380	495	720	1, 370	2, 610
	29	Toledo, Ohio	515	675	955	1, 820	3, 475
	30	Warren, Ohio	240	325	450	900	1, 715
	31	Wheeling, W. Va.	180	225	750	1, 020	1, 545
	32	Youngstown, Ohio and Sharon, Pa.	395	545	735	1, 415	2, 680
	33	Zanesville, Ohio	390	540	765	1, 470	2, 795
		Subtotal	4, 885	6, 625	9, 750	18, 220	34, 310
	17	AEC	2, 006	1, 207	500	2, 350	2, 350
		Total PSA 9	6, 891	7, 832	10, 250	20, 570	36, 660
10	34	Ashland, Ky.	100	170	230	400	710
	35	Bluefield, W. Va.	180	220	290	510	900
	36	Charleston, W. Va.	420	563	730	1, 290	2, 280
	37	Danville, Va.	45	65	85	150	270
	38	Hazard-Pikeville, Ky.	70	85	110	200	350
	39	Huntington, W. Va.	175	245	325	570	1, 010
	40	Kingsport-Tenn. (AEP)	195	260	350	615	1, 090
	41	Logan-Williamson, W. Va.	85	100	130	230	410
	42	Lynchburg, Va.	80	135	180	315	560
	43	Pulaski, Va.	105	140	205	360	640
	44	Roanoke, Va.	190	290	385	670	1, 190
		Total PSA 10	1, 645	2, 273	3, 020	5, 310	9, 410

EXHIBIT II.10—Continued

East Central Region—Estimated Annual Peak Demands by General Load Areas (Megawatts)—Con.

PSA	Map No.	General load areas	1960	1965	1970	1980	1990
11	45	Detroit, Mich	2, 858	4, 065	5, 640	10, 000	17, 410
	46	Flint, Mich	442	604	840	1, 490	2, 590
	47	Saginaw, Bay City, Mich	365	514	710	1, 270	2, 200
	48	Lansing, Mich	267	360	500	890	1, 540
	49	Jackson, Mich	210	270	370	660	1, 160
	50	Muskegon, Traverse City, Mich	288	413	570	1, 020	1, 770
	51	Grand Rapids, Alma, Mich	388	530	730	1, 310	2, 270
	52	Kalamazoo, Battle Creek, Mich	288	389	540	960	1, 660
		Total PSA 11	5, 106	7, 145	9, 900	17, 600	30, 600
12	53	Benton Harbor, Mich	210	285	400	800	1, 400
	54	South Bend, Ind	582	701	1, 000	1, 900	3, 500
	55	Gary, Ind	468	693	1, 000	1, 900	3, 500
	56	Ft. Wayne, Ind	234	326	500	900	1, 700
	57	Kokomo-Muncie, Ind	625	766	1, 100	2, 000	3, 900
	58	Greater Indianapolis, Ind	980	1, 353	1, 900	3, 600	6, 900
	59	Terre Haute, Ind	264	367	500	1, 000	1, 900
	60	Dayton, Piqua, Ohio	630	895	1, 300	2, 400	4, 600
	61	Cincinnati, Ohio, Aurora, Ind	1,021	1, 361	1, 900	3, 700	6, 900
	62	Louisville, Ky., New Albany, Ind	714	1, 027	1, 400	2, 800	5, 200
	63	Evansville, Ind., Henderson, Ky	276	375	500	1, 000	1, 900
		Total PSA 12	6, 004	8, 149	11, 500	22, 000	41, 400
19	64	Owensboro, Lewisport, Ky	61	85	355	500	815
	65	Greenville, Ky	33	53	75	170	365
	66	Morganfield, Ky	11	22	30	70	155
	67	Elizabethtown, Ky	23	40	55	125	275
	68	Lexington, Ky	125	233	350	765	1, 665
	69	Maysville, Ky	17	32	45	100	220
	70	Pineville, Ky	28	72	105	230	500
		Undistributed	374	427	753	1, 513	3, 497
		Total PSA 19	672	964	1, 768	3, 473	7, 492

EXHIBIT II.11



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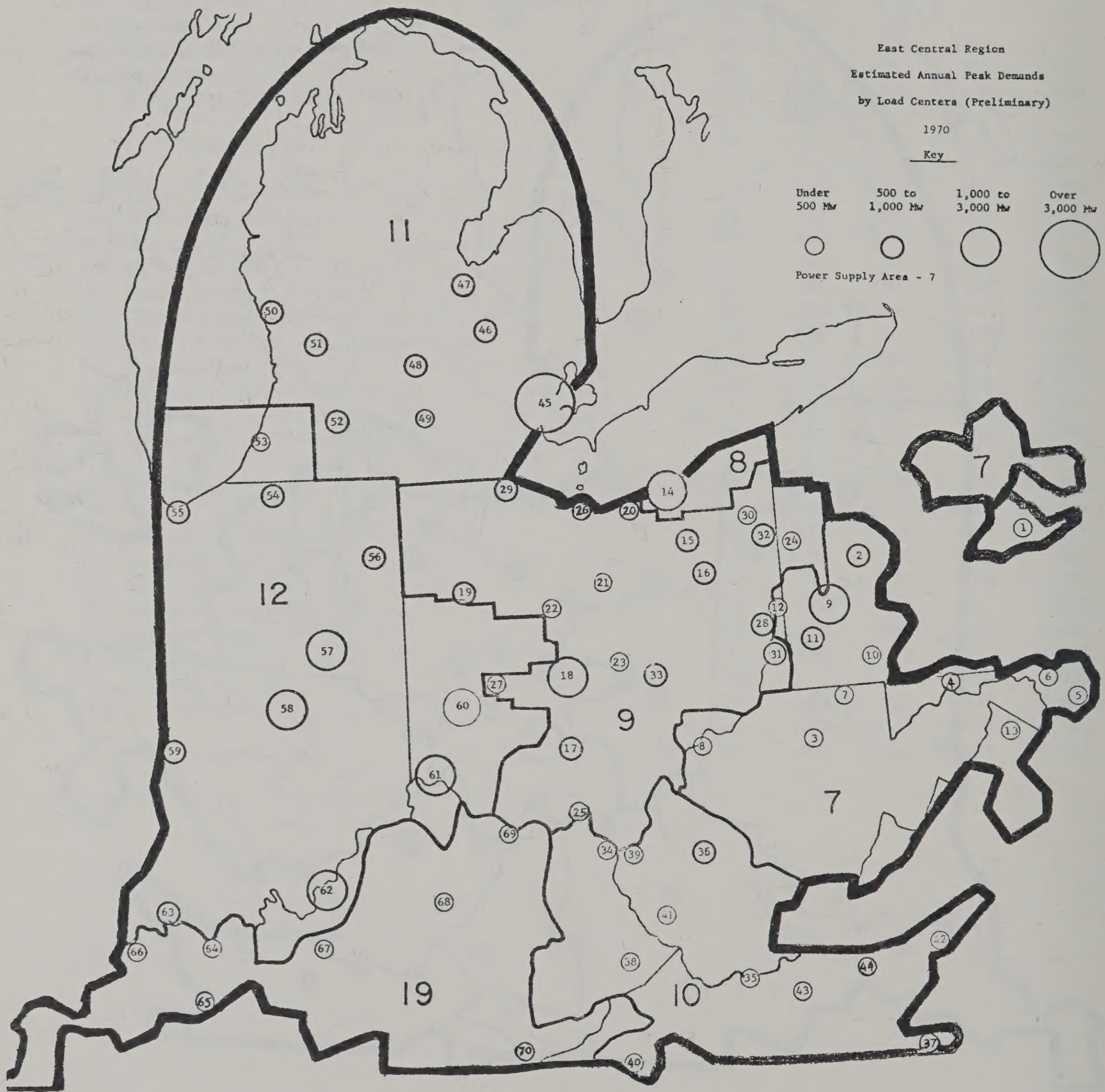

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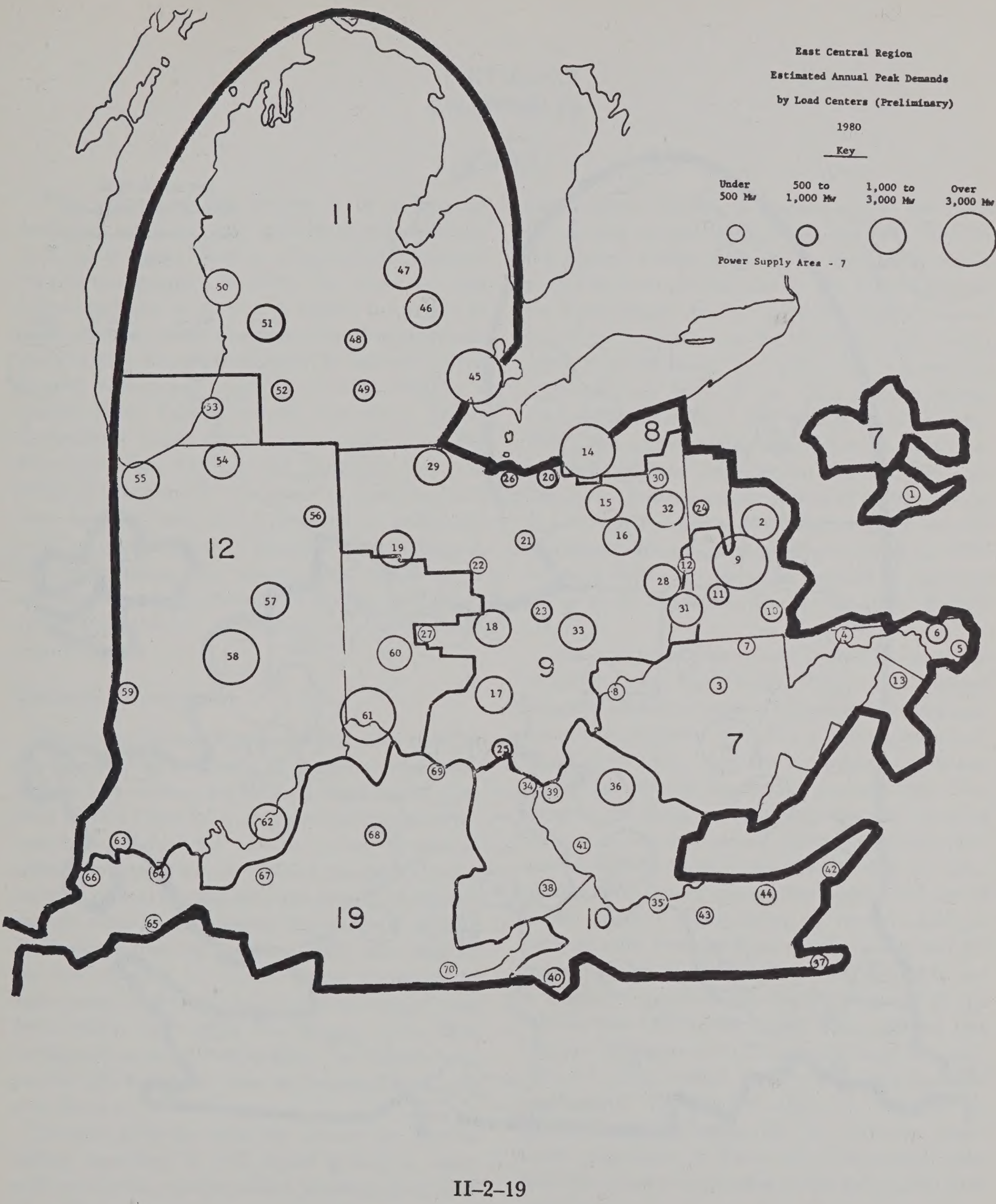

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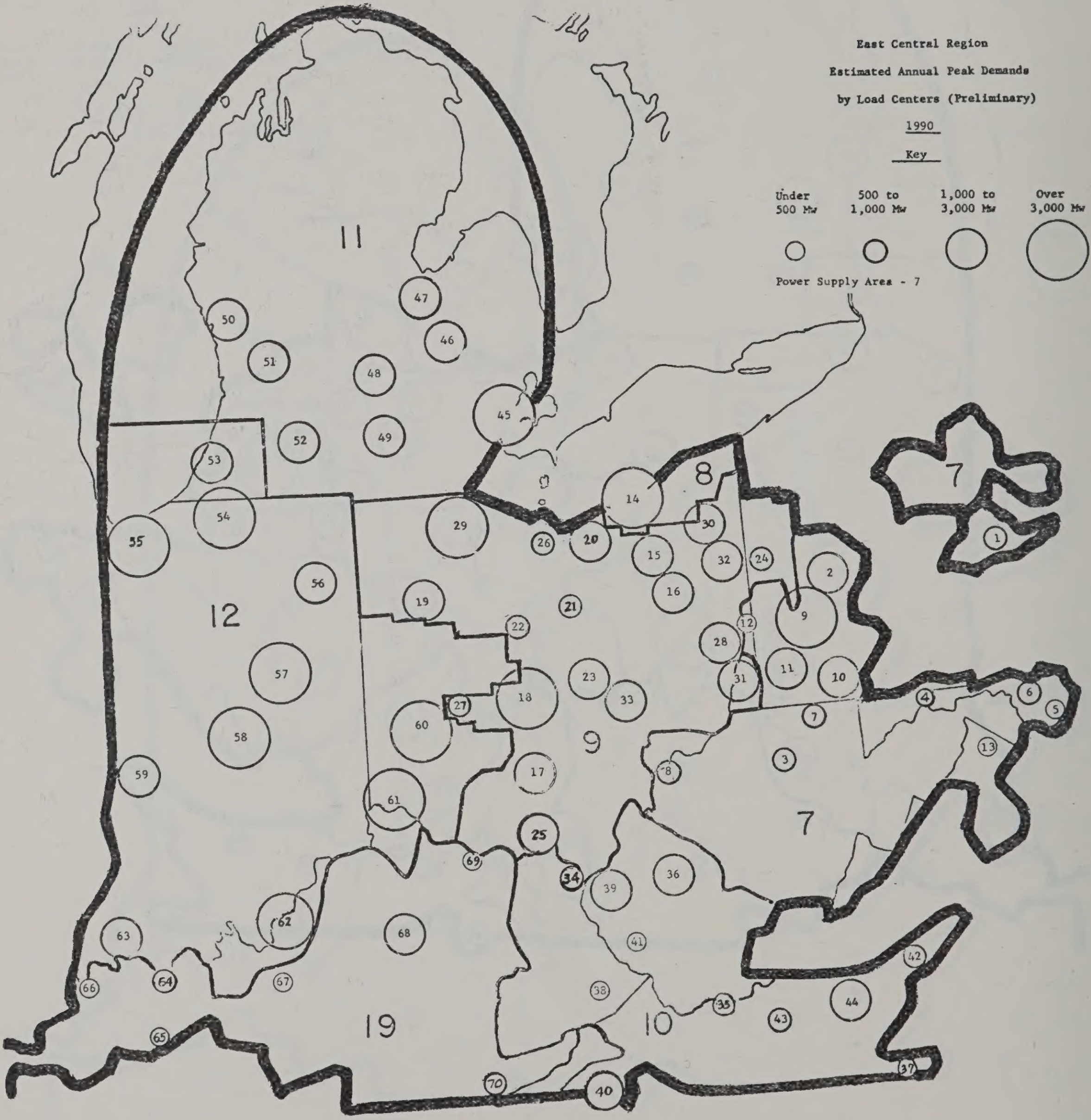


CHAPTER III

FUELS

The purpose of this chapter is to review the fossil-fuel resources and anticipated requirements in the East Central Region in the light of projected electric energy needs to 1990. The discussion that follows is based in part on a report, in process of publication, entitled "Fuel Resources, Requirements and Costs for Electric Generation In Eastern United States," which was prepared in early 1968 by a special Fossil Fuel Resources Committee (Fuels Committee) made up of representatives of the Northeast, East Central and Southeast Regional Advisory Committees. That report's projections have been modified here, where necessary, to reflect the most current thinking of the East Central Region utilities regarding their future energy requirements and the rate of introduction of nuclear generation vis-a-vis coal-fired generation to meet those requirements.

General Discussion

The East Central Region encompasses some of the largest concentrations of medium- and high-volatile bituminous coal in the United States (Exhibit III.1). Historically, this area has furnished the vast bulk of fuel for electric power generation within the region and, in addition, has been a major supplier of coal to utilities in the eastern and southeastern areas of the country. Reference to Exhibit III.2 shows that for the year 1967, over 90% of the coal shipped to electric utility plants in the states comprising the East Central Region originated from within the region. The balance came from contiguous areas in Pennsylvania and Illinois. Appendix III–A defines these originating bituminous coal districts.

Concern with the need for cleaner air and resulting legislation in this regard at federal, state, and local levels, together with a growing acceptance of nuclear generation as an economic alternative to fossil-fired plants, has had a marked effect on utility projections of future fuel sources for electric energy production in the nation. The 1964 National Power Survey, as pointed out in the Fuels Committee report, forecast that by 1980, 10% of the electric energy produced in the United States would be from nuclear plants. The Fuels Committee report shows that for the three regions covered by its study (Northeast, East Central, and Southeast), nuclear power is expected to account for approximately 46% of the total electric energy generated in the year 1980 and 65% in the year 1990. The corresponding figures for the East Central Region alone are given as 31% and 49%, respectively. A more recent survey of major utilities in the region indicates a somewhat lesser but still significant amount of nuclear generation in 1980 of about 24% with the same amount as projected in the Fuels Committee Report for 1990 (Exhibit III.3).

The substantially lesser role of nuclear power anticipated in the East Central Region as compared with the other two regions reflects the greater economic attractiveness of coal as a fuel source as well as an expectation that the air pollution problem can be ameliorated appreciably in the future. The latter is now being accomplished to some extent by the use of low-sulfur coal where practicable and available so as to minimize the emission of sulfur dioxide from power plants, the widespread use of highly efficient precipitators to remove substantially all solid material from the flue gases, and the increasing use of tall stacks of 800 to 1,200 feet in height to provide better flue gas dispersal. By the mid to late 1970's it is hoped that practical and efficient desulfurization techniques may be available to reduce sulfur dioxide emissions into the atmosphere. This entire subject is discussed in greater detail in Chapter IX. Air pollution abatement, regardless of the method employed, may have the effect of increasing power generation costs significantly.

The use of low sulfur coals, i.e., 1% or less of sulfur, for power generation will be limited in the future by the fact that coal of this type is essentially

EXHIBIT III.1
COAL FIELDS OF THE UNITED STATES
(EAST CENTRAL REGION SHOWN IN OUTLINE)

EXHIBIT III.2

Shipments of Bituminous Coal to Electric Utility Plants in East Central Region (By Districts of Origin and States of Destination) Year 1967

[Thousand net tons]

State of destination	Districts of origin									
	Total	1	2	3 & 6	4	7	8	9	10	11
Ohio	30, 086	220	575	2, 917	21, 701	79	2, 583	2, 011		
Indiana	20, 624						650	5, 408	3, 767	10, 799
Michigan	19, 602	192	250	1, 107	8, 160	19	8, 268	838	249	519
West Virginia	12, 671	2, 046		5, 038	1, 011		4, 576			
Kentucky	14, 087						1, 674	10, 136	2, 277	
Virginia	3, 149			62		662	2, 425			
Pennsylvania	7, 651		7, 651							
Maryland	449			449						
Total East Central	108, 319	2, 458	8, 476	9, 573	30, 872	760	20, 176	18, 393	6, 293	11, 318

NOTE.—This exhibit is based on Table 8 of the Fuels Committee report, modified to include pertinent portions of the States of Virginia, Pennsylvania, and Maryland.

found only in the southwestern Virginia, southern West Virginia, and eastern Kentucky coal fields and will continue to be in high demand by the metallurgical industry. Also, coal of this type is not sufficiently available in itself to meet present or future generation requirements. Furthermore, low-sulfur coal in some instances cannot be burned in existing furnaces of generating units designed for other types of coal without creating operating difficulties or incurring high capital costs for furnace modification. This again emphasizes the need and importance for developing an effective means of sulfur dioxide removal from flue gas.

Although substantial growth in nuclear generation in the East Central Region is forecast for the period 1970–1990, the use of coal is expected to increase appreciably during that period, as shown in Exhibit III.4.

EXHIBIT III.3

Electric Generation by Type of Fuel and Hydro Power—East Central Region

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	199.7	98.2	244.2	96.9	279.9	81.4	348.9	74.8	371.3	58.6	428.1	49.9
Oil	.2	.1	.3	.1	.1		.1		.2		.2	
Gas	.2	.1	.4	.1	.2		.3	.1	.4	.1	.5	.1
Nuclear	.9	.4	4.3	1.8	57.5	16.8	110.0	23.6	254.0	40.1	420.1	49.0
Internal combustion	.1	.1	.4	.1	.6	.1	.5	.1	.7	.1	1.7	.2
Total	201.1	98.9	249.6	99.0	338.3	98.3	459.8	98.6	626.6	98.9	850.6	99.2
Hydro generation:												
Conventional	1.8	.9	2.4	.9	2.6	.7	2.6	.6	2.7	.4	2.6	.3
Pumped storage	.4	.2	.2	.1	3.3	1.0	4.0	.8	4.3	.7	4.0	.5
Total	2.2	1.1	2.6	1.0	5.9	1.7	6.6	1.4	7.0	1.1	6.6	.8
Total generation	203.3	100.0	252.2	100.0	344.2	100.0	466.4	100.0	633.6	100.0	857.2	100.0

NOTE.—This exhibit is based on Table 3 of the Fuels Committee report, modified to reflect more recent projections of energy requirements and the rate of introduction of nuclear power.

EXHIBIT III.4

Coal, Oil and Gas Fuels for Electric Generation—East Central Region

[Quantities of coal are in 10^6 tons; of oil in 10^6 bbls; of gas in 10^6 MCF. Equivalent tons are in 10^6.]

	1966		1970		1975		1980		1985		1990	
	Quantity	Equivalent tons	Quantity	Equivalent tons	Quantity	Equivalent tons	Quantity	Equivalent tons	Quantity	Equivalent tons	Quantity	Equivalent tons
East Central:												
Coal	82.3	82.3	99.7	99.7	112.0	112.0	135.5	135.5	144.0	144.0	166.3	166.3
Oil	.3	.1	.5	.1	.2		.2		.3	.1	.3	.1
Gas	2.0	.8	3.8	.2	1.8	.1	2.8	.1	3.8	.2	4.8	.2
Total		83.2		100.0		112.1		135.6		144.3		166.6

NOTE 1.—This exhibit is based on Table 5 of the Fuels Committee report, modified to reflect more recent projections of energy requirements and the rate of introduction of nuclear power.

NOTE 2.—Fuel quantities are based on kilowatthour generation by fuels and assumed weighted average heat rates (Btu per kWh) of 10,300 for 1966; 10,200 for 1970; 10,000 for 1975; and 9,710 for 1980 through 1990.

This exhibit indicates that coal requirements for power generation are expected to about double from the reference year 1966 to 1990, even though the relative position of coal in total energy generated is predicted to decline from about 98% in 1966 to about 50% in 1990. These relationships, in terms of percentages of total energy generated in the region, are shown in Exhibit III.5.

The use of oil and gas for power generation has always been minimal in the East Central Region and is expected to remain of negligible significance in the future (Exhibits III.3 and III.4). This, of course, reflects the abundance of coal and its availability at substantially lesser cost. Similarly, because of the small amount of undeveloped hydro in this region, hydro will continue in the future to have a relatively minor effect on fossil or nuclear fuel requirements.

Fossil Fuel Reserves

The nation's known reserves of coal of the type commonly used are more than adequate to meet the needs of the electric utilities and other consumers well beyond the year 1990. Coalbearing formations are widely distributed throughout the nation (Exhibit III.1). On the basis of calorific value, about 55% of the total reserves are east of the Mississippi River.

The Appalachian region contains the largest reserve of high-quality, high-rank coals in the United States. The estimated total remaining reserve of bituminous coal in the region is 259,000 million tons (129,500 million tons at 50% recovery) of which approximately 84% is high-volatile, 9% medium-volatile, and 7% low-volatile. These coals generally have low moisture, and high calorific values that range between 12,500 and 14,500 Btu per pound. In addition to these Appalachian reserves, approximately 72,000 million tons (36,000 million tons at 50% recovery) of coal reserves in Indiana and West Kentucky are located within the East Central Region.

The Appalachian Region is the nation's storehouse of high-grade coking coals. Notwithstanding heavy demands on these coals for the coke ovens of the American steel industry (to which much of it is committed for the future through captive ownership), the coking coal reserves of this region are more than adequate to meet all foreseeable demands of the metallurgical coke industry. Generally, these coals are also excellent for electric utility plants where air pollution is a problem, although their costs are appreciably higher than lower-grade coals conventionally used for steam power generation, and their availability in the future will be limited.

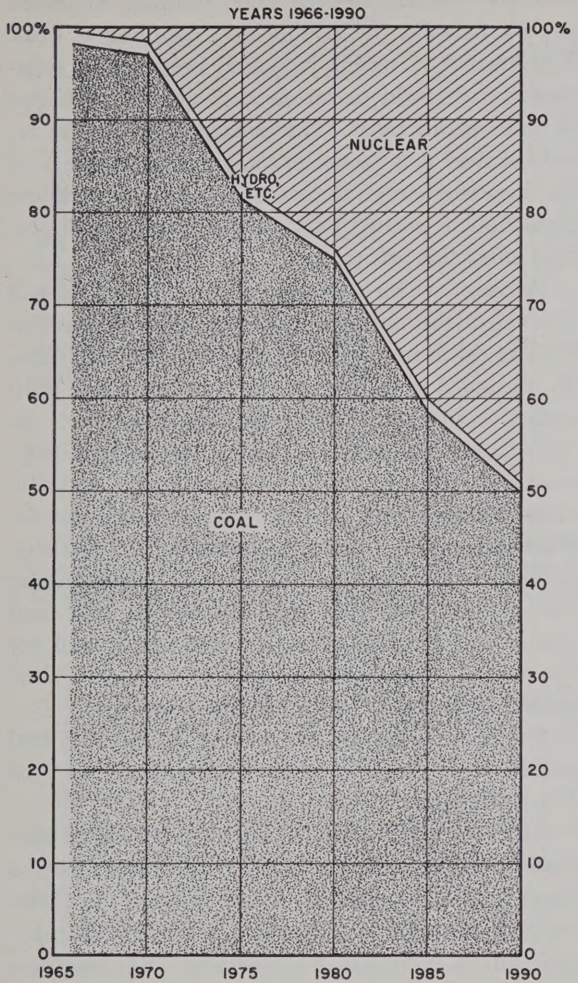
As air pollution becomes a matter of increasing concern throughout the nation, the minimum reserves and availability of lower sulfur coals are of prime importance to the coal and electric utility industries, and also to the general public. In addition to problems of availability resulting from shifts to lower sulfur coal and changes in burning facilities, substitutions generally will mean increased costs of coal, as lower sulfur coals are in higher-cost mining areas and, in general, at greater transportation distances than coals conventionally used for electric generation. This problem may be significantly relieved, as referred to above, with the development of practical commercial processes for the reduction of sulfur in coal and the reduction or removal of sulfur dioxide from stack gases.

Exhibit III.6 gives estimates of coal reserves by percent of sulfur content for the states encom-

EXHIBIT III.5

EAST CENTRAL REGION

PERCENT ENERGY GENERATED BY TYPE OF FUEL & HYDRO POWER



passed wholly or in part by the East Central Region. As previously indicated, the low-sulfur coals (1% or less) are concentrated in the southwestern Virginia, southern West Virginia, and eastern Kentucky coal fields and constitute 25% or less of the estimated reserves. The approximate weighted average of sulfur content for coal reserves in these states is about 2.2%. (The average sulfur content of coal used by all electric utilities in the United States in 1964 was 2.3%.)

By the way of rough comparison, the total reserves shown in Exhibit III.6 are 60 to 70 times greater than the tonnage required to take care of the approximately 65 million kW of coal-fired generation projected in the East Central Region for installation during the period 1970–1990.

The mere availability of coal reserves, however, is not a sufficient basis for their remaining an economical fuel alternative for power generation. Some of the factors affecting the choice of coal as a future fuel, particularly as related to air pollution, have already been mentioned. Additional, of course, is the question of price and price stability, including transportation costs. The choice between fossil and nuclear generation in the East Central Region will continue to rest to a substantial degree on the competitive interplay between these two energy sources.

Fossil-Fuel Price Considerations

An important factor contributing to availability of coal at competitive prices is the extent to which new productive capacity is added to the coal in-

EXHIBIT III.6

Preliminary Estimates of Coal Reserves Comprising States Wholly or in Part in East Central Region—January 1, 1965

[Million net tons]

State	Percent sulfur content									
	0.7 or less	0.8–1.0	1.1–1.5	1.6–2.0	2.1–2.5	2.6–3.0	3.1–3.5	3.6–4.0	Over 4.0	Total
Bituminous coal:										
West Virginia	20,761.0	26,710.6	21,819.7	13,290.6	8,496.1	2,491.8	3,147.4	5,949.2		102,666.4
Kentucky:										
East	13,639.9	8,491.9	2,286.8	1,658.8	1,158.3	2,154.4	24.7			29,414.8
West			1,119.6	162.0	336.3	3,793.6	12,759.3	13,643.3	5,081.3	36,895.4
Virginia	1,981.5	6,077.5	1,637.1		123.9					9,820.0
Indiana	197.5	173.0	3,645.2	4,248.8	3,543.4	4,110.5	10,872.8	5,105.9	2,944.0	34,841.1
Pennsylvania	44.0	1,154.4	7,624.4	12,424.9	19,689.5	9,995.6	5,287.6	1,150.5	580.6	57,951.5
Maryland				124.6	191.8	208.2	378.6	56.4	220.4	1,180.0
Michigan								205.0		205.0
Ohio		611.0	369.0	2,110.2	2,750.4	7,810.5	9,785.3	10,148.2	8,439.4	42,024.0
Total bituminous	36,623.9	43,218.4	38,501.8	34,019.9	36,289.7	30,564.6	42,255.7	36,258.5	17,265.7	314,998.2

NOTE.—This exhibit is based on Table 6 of the Fuels Committee report, modified to include only those states wholly or in part within the East Central Region.

Source: Bureau of Mines, Department of the Interior, Information Circular 8312.

dustry. Without question, considerable capital investment will be required in the future if the demands for coal in the production of electric energy are to be met. This problem has two aspects, one related to the sheer magnitude of the future gross tonnages to meet the power industry's demands, and the other related to the growing amounts of coal required to supply specific power plant projects. The trend toward increased size of fossil-fired generating units and plants in order to achieve economies of scale, and the need to utilize fully the available plant sites, means large coal commitments. For example, a generating plant with an aggregate capacity of 3,000 MW, which can be considered reasonable in the future, will require an annual coal supply of approximately 7.5 million tons. For a useful life for each of its units of 30 years, this means an overall guaranteed supply of about 200 million tons. Such large plants in many cases must utilize unit trains and other large-quantity coal movements and they cannot be economically supplied from a large number of scattered mines. Relatively few coal mines in the country today have a productive capacity in excess of 5 million tons a year. As a matter of fact, only five bituminous coal mines produced 5 million tons or more in 1967, and only six additional mines produced over 3 million tons annually. The 50 largest U.S. bituminous mines produced 135.9 million tons in 1967, which is an average of 2.7 million tons per mine. To provide assured sources of coal in the huge quantities required in the future will require large capital investments in production facilities with long-term commitments for their output.

The coal industry during the past two decades has contributed significantly to price stability in fuel prices. This was brought about mainly through extensive mechanization, and resulting increased productivity, in the mining and handling of coal. Unfortunately, recent increased costs of an inflationary nature in materials and labor have begun to reverse this trend. This is confirmed by the results of the Fuels Committee's survey. Also, the need for improvements in mine safety and toward the reduction in occupational health hazards will further affect this price trend.

Prices at which coal now and in the future will be available in different areas vary depending upon differences in mining methods and costs, coal quality, distances from point of mining to points of utilization, and many other factors. However, the principal components making up the price of delivered coal are (1) the f.o.b. mine price, and (2) transportation costs. Exhibit III.7, taken from the Fuels Committee report, indicates the relationship between these two factors and their trends during the period 1961–1966 for bituminous coal and lignite for the United States as a whole and for the three eastern regions of Continental United States (referred to below as "Eastern").

Exhibit III.8 shows the amount and cost of coal consumed in 1966 by electric utilities in the East Central Region.

In its survey, the Fuels Committee solicited estimates from the utilities in the East Central Region regarding long-range cost trends in fossil fuels. The estimates exhibited wide variations, indicating the difficulty in making such projections. The committee

EXHIBIT III.7

Trends in Coal Costs (1961–66) for United States and Eastern Regions

Year	Total production (million tons)		Average value f.o.b. mine (per ton)		Average rail freight rate (per ton)		Average mine value plus average rail (per ton)	
	United States	Eastern	United States	Eastern [1]	United States	Eastern [2]	United States	Eastern
1961	403	336	$4.58	$4.64	$3.40	$3.45	$7.98	$8.09
1962	422	352	4.48	4.56	3.32	3.39	7.80	7.95
1963	459	383	4.39	4.46	3.21	3.28	7.60	7.74
1964	487	406	4.45	4.52	3.11	3.16	7.56	7.68
1965	512	426	4.44	4.54	3.13	3.17	7.57	7.71
1966	534	442	4.54	4.65	3.01	[3] 3.05	7.55	7.70

[1] Excludes Illinois.

[2] Includes Illinois.

[3] Preliminary.

EXHIBIT III.8

Coal Consumption and Costs for 1966 by Electric Utilities—East Central Region

States	Coal consumed (000 tons)	Cost per ton as burned	Cost per 10^6 Btu as burned (cents)
Ohio	26, 645	$5. 23	22. 4
Indiana	19, 506	4. 84	21. 5
Michigan	17, 522	7. 33	29. 1
West Virginia	10, 789	4. 23	17. 8
Kentucky	12, 557	3. 72	16. 3
Virginia	3, 062	4. 28	17. 5
Pennsylvania	8, 414	4. 44	18. 8
Maryland	950	4. 56	19. 5
Total East Central Region	99, 445	5. 12	21. 7

NOTE.—This exhibit is based on Table 10 of the Fuels Committee report, modified to include the pertinent portions of the states of Virginia, Pennsylvania, and Maryland.

reported, however, that a generalized summation of those responses which were received indicated a relatively stable price, increasing from about 22.5 cents per million Btu in 1965 to about 25 cents per million Btu in 1990. The achievement of these prices will constitute a considerable challenge which undoubtedly must be met in the face of continued inflationary trends.

Coal continues to be the largest single item of all railroad traffic. In the East Central Region, rail transport accounted for approximately 42% of all coal tonnage loaded at the mines in the year 1967. The balance was divided between shipments by water and truck. Exhibit III.9 shows this by coal-producing districts for the East Central Region.

The development and use of the "unit train" has resulted in important cost reductions. The unit train, consisting of lightweight, large-capacity cars, carries up to 12,000 tons or more of coal on regular schedules between a single mine or group of mines, and a single power plant destination. An increased number of coal companies and utilities have invested in coal cars of their own to obtain the benefits of even greater rate reductions with unit train service.

While unit trains provide trainload movements to many of the major electric generating plants at substantially reduced rates, the "shuttle train" offers some of the more imaginative innovations in energy transportation that may contribute to lower fuel costs. The shuttle train is designed and operated solely to provide fast express service between a single coal mine and plant. It usually includes such features as large-capacity cars with locomotives at several locations within the train, loading and unloading in motion, and elimination of classification yards and layover points.

Both the unit train and the shuttle train should result in additional reductions in costs for coal transportation over more conventional methods. On

EXHIBIT III.9

Shipments of Bituminous Coal to Electric Utility Plants, East Central Region (By Districts of Origin and Method of Shipment) Year 1967 [1]

[Thousand net tons]

Methods of shipment	Percent	Districts of origin									
		Total	1	2	3 & 6	4	7	8	9	10	11
East Central:											
All-rail	42	40, 943	2, 049	234	276	14, 422	8	6, 178	5, 591	5, 653	6, 532
River and ex-river	26	24, 867	....	31	4, 391	3, 522	71	6, 172	7, 818	391	2, 471
Great Lakes	14	13, 703	192	250	1, 030	5, 831	19	5, 337	276	249	519
Truck	11	10, 202	217	310	961	3, 132	....	64	4, 708	....	810
Tramway, etc.[2]	7	7, 355	.....	.....	2, 404	3, 965	.....	.....	.....	.....	986
Total East Central	100	97, 070	2, 458	825	9, 062	30, 872	98	17, 751	18, 393	6, 293	11, 318

[1] Source: Bureau of Mines, Department of the Interior.
[2] Tramway, conveyor, and private railroad.

NOTE.—This exhibit is based on Table 9 of the Fuels Committee report.

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balance, however, freight rates will undoubtedly increase in the future if inflationary trends continue.

The feasibility of moving coal in slurry form by pipeline was successfully demonstrated by the 108-mile pipeline from Cadiz, Ohio, to the East Lake Plant of The Cleveland Electric Illuminating Company (CEI) which operated between 1957 and 1963. The pipeline operation was discontinued when lower trainload rates for bituminous coal to all CEI plants, induced in part by the pipeline, rendered it economically unattractive. Presently under way in the Far West in connection with the Mohave generating plants in southeast Nevada, is a 275-mile long coal pipeline from northern Arizona which, studies indicate, will be competitive with rail transportation.

The availability of the Ohio River and its major tributaries across large parts of the East Central Region will assure the continued importance of coal shipment by water in the overall pattern of coal transportation within the region.

Mine-Mouth Power Plants

The concept of locating power generating facilities at or near a coal mine, i.e., so-called mine-mouth plants, has received renewed attention in recent years. With technological advances in EHV transmission which permit transportation of power over greater distances, and with the further development of interconnected systems, the economic application of the mine-mouth concept has increased. The advantages of mine-mouth plants, in addition to their lower fuel costs, include frequently the opportunity to extend transmission facilities on an economical basis at an earlier date than it otherwise would be possible. This may permit the realization of further benefits of interconnection and transmission development. Also, in some instances, mine-mouth plants, by their remoteness from metropolitan load centers, may lessen the air pollution problem in such areas.

On the other hand, mine-mouth generation for the supply of remote load centers cannot be regarded as a generally feasible technical-economic means for providing such areas' full energy requirements. The cost and increasing difficulty of securing the additional transmission line rights-of-way, the need for the continued installation of generation near the load center to assure reliable and satisfactory system performance, and the need for such mine-mouth projects to compete with nuclear generation and with alternative methods of fossil-fuel transportation, will have a limiting effect on such applications. In general, the transmission of electric energy from power plants located at or near the coal mines is one more form of energy transportation which will continue to compete with other transportation forms, such as railroads, in the future.

Many utilities in the East Central Region, by virtue of their proximity to major coal-producing fields, have had a long history in developing power plants at or near the coal mines. One of the earliest of these ventures was the Windsor Plant, placed in operation in 1916–1918 and jointly owned by West Penn Power Company (Allegheny Power System) and Ohio Power Company (American Electric Power Company). The mine supplying the coal requirements for this plant was developed as an integral part of this project. A more recent development is the Muskingum River plant of Ohio Power Company (AEP) which, with a generating capacity of 1,495,000 kW, draws its entire coal supply from one utility-owned coal field with a utility-owned electric railway and a 4½-mile belt conveyor system. There are several other instances of plants in the East Central Region in which the entire coal supply is furnished from one mining operation over utility-owned transportation systems.

In addition, as indicated above, many of the power plants in the East Central Region, while not mine-mouth in the strict definition of the term, are in close proximity to coal-producing fields and depend on truck, rail or barge shipment from a number of coal suppliers within a short or relatively moderate geographical distance. Because of this proximity of coal to load centers in the East Central Region, as compared with many other areas of the country, power plants at or near the coal mines will continue to be a competitive force in the energy picture.

Natural Gas and Oil for Electric Generation

Natural gas as fuel for electric generation in the United States during the 5-year period from 1961 to 1966 increased from 1.8 to 2.6 trillion cubic feet, an average annual growth rate of 7.4% for the period. This represents 14.6% of the total natural gas requirements of 17.8 trillion cubic feet in 1966.

The amount of electricity generated in the East Central Region using natural gas as a fuel is relatively minor, as shown in Exhibit III.3, being only

0.1% of the total electric generation in 1966. While the amount of gas used in the East Central Region for electric energy production is estimated to increase from 2 billion cubic feet in 1966 to 4.8 billion cubic feet in 1990. (Exhibit III.4), the percent of total electricity generated from gas in 1990 is not expected to increase over the 1966 figure (Exhibit III.3). While natural gas may play an increasing role in the East Central Region as a fuel for firing gas turbine generating units and "stripped down" peaking plants, and in some instances as replacement fuel in older coal-fired boiler plants where the cost of air pollution control equipment cannot be justified, its overall use as a fuel for electric generation is expected to remain relatively minor.

Oil as a fuel for electric generation has an insignificant position in the East Central Region, comparable to that of natural gas. Its role, as indicated in Exhibit III.3 is expected to diminish even further in the future.

CHAPTER IV

SOURCES OF POWER SUPPLY

The discussion which follows outlines the basic factors which enter into a determination of the type and mix of generating plant to be installed in the East Central Region in the future, the considerations affecting plant location, and possible trends in overall generation technology. The mix of primary energy sources to meet expected demands within the region is a matter that will require continual review every time a new generating unit or plant is committed. The type of capacity selected inevitably will reflect its economic competitiveness at the time of commitment as well as its anticipated role in meeting the system's future energy needs. In addition, the state of the art, in terms of both air pollution and thermal effect, will influence significantly the choice of generation mix. The location of capacity, while constrained by site availability, load distribution, and transmission costs, will necessarily also conform to certain basic reliability considerations.

Primary Sources of Energy Supply

Fossil-Fired vs. Nuclear Generation

The sources of power supply to the East Central Region historically have been based on coal-fired generation because coal is a major natural resource of much of this area, as described in Chapter III. The vast reserves of recoverable coal still available for power generation in this region will continue to provide a powerful economic incentive for the development of coal-fired plants in any projection of electric generation into the future. This is borne out by the possible patterns of future generation outlined in Chapter X.

The fact that the electric power industry is coal's largest customer, and that in some parts of this region the economy itself is inextricably tied to coal, further supports this conclusion. This assumes, of course, that coal can maintain its competitive position vis-a-vis other fuels. To date, and in the near-term future, this appears to be the case for a substantial portion of the region. It also assumes that any adverse effect of stack gas emission can be controlled within acceptable limits by the use of tall stacks and, in the future, the application of sulfur-dioxide removal equipment.

The unavailability and high cost of residual oil precludes its use as a major fuel for power generation in this region, excepting in small quantities required for power plant start-up and occasional peaking and emergency use. Similarly, the lack of natural gas in the quantities required and at competitive prices will relegate it to a relatively minor role as a source of electric power generation. Except for its use in combustion engines and gas turbines designed for peaking operation at a relatively few hours annually, natural gas is not expected to become a major fuel for power generation in the future (Chapter III).

Fossil-fired generation, i.e., essentially coal, will constitute approximately 92% of all capacity requirements, in terms of kilowatts, in the East Central Region in 1970. While nuclear generation will gradually take on an increasingly important role, it is estimated that in 1990 about 60% of all electric generating capacity will still be provided by fossil-fired plants. Exhibit IV.1 shows the relative roles of fossil-fired, nuclear, and other types of generation—largely hydro and pumped storage—projected for the years 1970, 1980, and 1990. This exhibit indicates, by type, both the additions and total installed amounts of generating capacity in each period, in percent. These relationships are further discussed in Chapter X.

The rapid acceptance in recent years of nuclear generation by the power industry has found its counterpart in the East Central Region. For the 3-year period 1966–1968, when the bulk of past commitments for installation of nuclear generation were made by the power industry, approximately 58,000 MWe, or 47% of all new thermal generating capacity ordered in this country, was nuclear. During the same period, utilities in the East Central

EXHIBIT IV.1

Generating Capacity by Type in East Central Region

[In percent of total]

Type	1970 installed	1971–80 additions	1980 total	1981–90 additions	1990 total
Fossil......	92	[1] 60	76	43	60
Nuclear....	2	[2] 32	16	55	34
Other......	6	[3] 8	8	2	6

[1] Committed—24.2%.
[2] Committed—12.2%.
[3] Committed—6.3%.

Region committed themselves to the installation of 7,042 MWe of nuclear generation, constituting approximately 49% of their total thermal generation needs. While this would tend to indicate an evolving pattern of generation expansion in the East Central Region very similar to that in the nation as a whole, future projections show substantial divergence from other areas, such as the northeastern and western sections of the country. For example, the report prepared by the Northeast Regional Advisory Committee shows 58.4% of 1990 load requirements of the Northeast Region as being met by nuclear generation. This compares with 34% for the East Central Region, as shown in Exhibit IV.1. The basis for this divergence is in large part due to the relatively weaker competitive position of nuclear-fueled generation vis-a-vis coal-fired plants in this region. It also reflects the fact that in many instances the problem of air pollution, which undoubtedly is a strong factor favoring nuclear in certain densely populated sections of the country, is not quite as severe in many parts of the East Central Region. This results from the greater ability of utilities in this region to locate new power plants somewhat remote from congested areas, either in close proximity to coal supplies or with access to relatively attractive coal transportation arrangements.

Prior to 1968, nuclear-fueled plants were adjudged competitive with fossil-fired plants, at coal costs in the order of 23 to 24 cents per million Btu. In view of the sharp increases being experienced in nuclear costs, this is no longer the case. Reference to Exhibit III.8 shows average coal costs in the East Central Region, during the period when the bulk of the presently committed nuclear-fueled capacity was placed on order, as 21.7 cents per million Btu. While coal costs since have risen, and while it is apparent that they will increase further in the future, the fundamental question is whether or not the increased costs of nuclear generation will maintain a competitive balance with coal even at its higher price.

Nevertheless, the role of nuclear generation in the supply of energy requirements in the East Central Region is expected to increase materially in the future, as indicated in Exhibit IV.1. While these projections reflect the overall judgment of the major power suppliers in the region, as developed during the past year, all utilities are keenly aware of the current rapid rises in generating equipment costs. Such cost rises have been more predominant in nuclear than in fossil-fueled generating equipment. The problems and uncertainties of siting and regulatory approval, as well as the delays in meeting construction targets, have also been more severe in nuclear than in conventional generation. These factors, together with changing cost relationships, the operating performance of future nuclear units, and the success of the utility industry in relieving any adverse atmospheric effects from fossil-fired plants, may well alter the prognostications discussed above.

Exhibit IV.2 shows all nuclear-fueled generation now in operation or committed in the East Central Region.

It will be noted that the vast bulk of this capacity is located relatively distant from the region's coal fields. It is expected that nuclear generation will find its greatest application during the next decade or so in the northern portions of the region, with plants located mainly on Lakes Erie and Michigan where there is access to cooling water.

Hydro Generation

The East Central Region has a relatively small amount of conventional hydro resources. To a large extent these have already been developed. The total hydro capacity in the region amounts at present to 681 megawatts. To explore undeveloped potential hydro sites in the East Central Region, a survey of all utilities in the area was made using a list of sites provided by the Chicago Office of the Federal Power Commission in April 1967. This list showed about 4,600 MW of potential capacity distributed among some 60 different locations. The responses to this survey indicated that most sites were regarded as uneconomical for generation projects. The few hydro sites, indicated by the utilities

EXHIBIT IV.2

Nuclear-Fueled Plants in Operation or Committed in East Central Region [1]

Plant	Prime utility	NSSS vendor	MWe	Year of operation
Shippingport	Duquesne Light	W	100	1957
Big Rock Point	Consumers Power	GE	70	1963
Fermi No. 1	PRDC (Detroit Ed.)	APDA	61	1964
Piqua [2]	City of Piqua	AI	11	1964
Palisades	Consumers Power	CE	770	1970
Cook No. 1	Ind. & Mich. (AEP)	W	1,054	1972
Cook No. 2	Ind. & Mich. (AEP)	W	1,054	1973
Beaver Valley	Duquesne Light Ohio Edison	W	847	1973
Fermi No. 2	Detroit Edison	GE	1,127	1974
Davis-Besse	Toledo Edison Cleve. Elec. Illum.	B & W	890	1974
Midland No. 1	Consumers Power	B & W	[3] 500	1974
Midland No. 2	Consumers Power	B & W	800	1975

[1] As of July 1, 1969.
[2] No longer in operation.
[3] This reactor will deliver process steam to a manufacturer.

as worthy of consideration, were located at navigation dams on the Ohio River. These included Cumberland Falls, Gallipolis, and Racine. Any development at Cumberland Falls, however, has met strenuous objections by local citizens' groups because of eventual inundation of scenic and tourist attractions. Application for a license to install 40 MW of capacity of Gallipolis has been filed with the FPC some time ago but the U.S. Corps of Engineers plans for making changes in the dam have delayed the project. Application for a license to install 40 MW of capacity at Racine has been filed recently and is now pending before FPC. From the above it can be seen that hydro will not play a major role as a power supply source to this region.

Pumped Storage Generation

Some parts of the East Central Region, by virtue of terrain and water resources, have offered and will continue to offer opportunities for the development of pumped storage generation for peaking purposes. At present, 765 MW of pumped storage generation is located within, or is available to, the East Central Region. This includes the Smith Mountain plant (460 MW) of Appalachian Power Company (AEP), and Cleveland Electric Iluminating Company's share (305 MW) of the 380-MW Seneca plant in northwestern Pennsylvania which it jointly owns with the Pennsylvania Electric Company (GPU). Two additional plants of about 1,800 MW each are planned. These comprise Consumers Power Company's and Detroit Edison Company's Ludington project in northern Michigan and Appalachian Power Company's (AEP) Blue Ridge project in southwestern Virginia; the latter is awaiting license approval. These plants are tentatively scheduled for 1973–1974, and 1975–1976, respectively. Consideration also is being given by the Allegheny Power System to the installation of pumped storage generation in the amount of 750 MW in the 1976–1980 period. Possible projections beyond these dates are shown in Chapter X.

While preliminary surveys indicate that potential pumped storage plant sites are numerous in the East Central Region, their relative concentration in remote portions of the area will limit their economic feasibility. Pumped storage generation is a form of peaking capacity and, therefore, cannot support a heavy transmission burden and remain economically competitive with alternative forms of peaking generation. Also, it is inherently energy limited because of reservoir storage and draw-down restrictions and, therefore, can satisfy only a limited portion of the daily load cycle.

Possible Sources of Power From Outside the Region

The East Central Region, by virtue of its large, economical fuel resources, has been an exporter of power in the past. With the increased installation of nuclear-fueled plants in adjacent regions,

this exportation of power may gradually decline in the future.

The recent closing of EHV ties between Michigan and the Indiana-Ohio area now interconnects the Province of Ontario with the entire East Central Region. The electric energy needs of Ontario Hydro are being met by a combination of fossil-fuel, nuclear and hydro generation. The 2,000-megawatt Lambton plant in Ontario, directly across from Michigan, utilizes coal imported from the United States. Ontario's needs and resources preclude the exportation of firm power to the East Central Region at costs that are competitive with power produced within the region.

The lack of any need or incentive to import firm power from outside the East Central Region will not preclude the continued interchange of emergency, short-term, diversity and economy power between systems in the region that are contiguous with systems in other regions.

Power Plant Siting

Adequate plant sites, both in terms of their numbers and their general adaptability for power production purposes, are essential to meet the growing electric energy demands of the future. The projected addition in the East Central Region of approximately 130,000 MW of new generation between 1971 and 1990 will require the intensive development of existing sites wherever possible, as well as the acquisition of a substantial number of new sites. No attempt was made in this survey to determine the precise site requirements of the utilities through 1990. Any such effort would require, as a starting point, a detailed engineering analysis of all existing sites to determine their ability to support additional generation. It is readily apparent, however, that the acquisition and development of power plant sites in the future will constitute one of the power industry's most difficult problems.

The discussion which follows describes some of the more important factors affecting site selection. These factors may be defined as: land requirements, cooling water needs, fuel availability and supply, transportation facilities, environmental effects, and location with regard to system load. This discussion will be limited to thermal plants since the unique requirements of hydro and pumped storage generation require their consideration on an individual plant basis.

Land Requirements

Coal-fired plants require on the average a minimum of about 60 acres for each 1,000 MW of capacity. The use of cooling towers and ponds would add to this requirement. A 3,000–MW plant, which is not an unrealistic size in the future, would require a minimum of approximately 180 acres. These acreages do not include ash disposal areas which must be found in the vicinity of the plant and, in general, require about 250,000 cubic feet per MW or about 180 acres of land utilized to a depth of 100 feet for the lifetime operation of a 3,000–MW plant. This demonstrates the value and desirability of developing industrial uses for fly ash and bottom ash, as referred to in Chapter IX.

The land requirements for nuclear-fueled plants are determined almost entirely by exclusion area criteria. These requirements may vary from plant to plant depending on the orientation of the plant with regard to open water and population areas. In general, however, current AEC criteria require nuclear plant sites to be much larger than fossil-fired plant sites. Typical values for site requirements have been 300 to 600 acres for a 2 200–MW plant comprising two units of 1,100 MW each.

Cooling Water Needs

The amount of cooling water required depends on the size of the plant, its efficiency (heat rate) and the permissible temperature rise of the cooling water. Where the permissible temperature rise is limited to 10° F, which is most often the case, minimum river flows in excess of 5,000 cubic feet per second or about 2,300,000 gallons per minute, would be required for a 3,000–MW plant which does not depend on cooling towers or pondage. Although this represents a minimal consumptive use of water, since the water simply flows through the condenser and returns to the source, it nevertheless is a very large quantity.

Greater limitations on permissible heat discharge have made it necessary with increased frequency to provide cooling towers and cooling ponds. A modern 3,000–MW cooling tower installation would require a flow of water in the order of 55 cubic feet per second or about 27,000 gallons per minute to replace the water evaporated, while a cooling pond, if feasible by terrain considerations, would require perhaps one-half this amount. Since a cooling pond depends for its effect upon surface evaporation, an

area of about 3,000 acres would be required for a 3,000–MW plant. The large area requirement for cooling ponds makes them impracticable in most instances.

The relatively lesser thermal efficiency of nuclear as opposed to fossil-fired plants and the fact that all heat losses in nuclear generation are discharged into water and none into the atmosphere, result in greater cooling water needs. Based on the most efficient present-day heat rates, the cooling water requirement for nuclear over fossil-fuel plants is about 1.5 to 1. This relationship is not expected to change significantly in the next decade or so.

The use of wet type cooling towers, both of the induced draft and natural draft hyperbolic design, is becoming increasingly prevalent in the East Central Region. Generating units as large as 800 MW are now being constructed with a single cooling tower. This trend is expected to accelerate since there are few sites on the rivers in the East Central Region with sufficient water to permit straight condenser cooling and still remain within present and anticipated river temperature constraints. The net effect on the plant capital cost of wet-type cooling towers is at present about $4 to $7 per kilowatt.

The assurance of sufficient cooling water supplies to large power plants, even during the worst drought conditions, is absolutely essential since such plants cannot be shut down during periods of low river flow without serious consequences to the power system in its ability to serve its customers.

Cooling towers are further discussed in Chapter IX on Environmental Considerations.

Fuel Availability and Supply

The importance of coal delivered to a site at competitive prices and in the quantities required for large fossil-fired plants has been discussed previously. A typical 3,000-MW plant would need about 7.5 million tons of coal per year from sources with assured recoverable reserves in the order of 200 million tons. While reserves are available in the region to meet such demands for many years to come, their development into large, efficient operations will require large amounts of investment and the full use of mine mechanization techniques.

The availability of plant sites in close proximity to large coal reserves, discussed above, is limited even in the East Central Region with its abundant coal reserves. This means that many future plants will need to depend on barge or rail transportation. Therefore, it will be essential to pursue new and more efficient means of bulk transportation if the price of coal delivered to the plant site is to be competitive. The full and imaginative cooperation of the transportation industry will be needed in this respect.

The availability of fuel for nuclear plants will depend, in the future, largely on the degree of increased uranium exploration, the development of sufficient ore processing capacity and the progress in the development of converter and breeder reactors. The ease in shipping nuclear fuel and the relative insignificance of fuel transportation as a cost factor makes nuclear plant siting as such independent of fuel supply.

Transportation Facilities

An important requirement in power plant siting is the availability of rail or water transportation. The increasingly large size of power plant equipment and components necessitates some means of bulk transportation to the plant site. In coal-fired plants such transportation is required not only during the process of construction and to permit replacement of heavy equipment during the plant's lifetime, but also to provide for delivery of coal. In nuclear-fueled plants, thhe very large size of plant components, particularly the pressure vessel, makes barge transportation almost a necessity at present. Possible future field erection of pressure vessels may ease this problem somewhat.

The East Central Region is well provided with a railroad network. In addition, it has access to Lakes Erie, Huron, and Michigan, as well as such major navigable streams as the Ohio, Allegheny, Monongahela, and Kanawha Rivers.

Environmental Effects

The increasing importance of environmental considerations in power plant siting has already been alluded to and is discussed in detail, particularly as regards fossil-fired plants, in Chapter IX. Such considerations must be carefully evaluated, site by site, with full recognition given to increasingly stringent restrictions on a plant's effect on air, water and the esthetics of a particular location.

Nuclear plants, while substantially eliminating the air pollution problem, do aggravate the so-called thermal pollution problem because of their greater heat loss to the cooling water used for condensing

purposes. Many other factors, unique to nuclear plant siting, also require consideration, such as the ability to dispose readily of radioactive waste products, population density and various safety requirements.

Location With Regard to System Load

The location of power plants in relation to system load has both economic and reliability implications. As plant sizes become larger, the need for transmission outlets increases. Therefore, the availability of transmission rights-of-way becomes a major factor in site selection. The more remote the plant from the load center the greater the cost for transmission to deliver its output to the consumer. While the growth of interconnected extra-high-voltage (EHV) networks throughout the East Central Region for purposes of reliability and coordinated operation will alleviate any cost penalty to some degree, the fact remains that the greater the distance from power source to load center the greater the energy transportation cost associated with such energy.

Reliability considerations also dictate against the excessive concentration of power sources. Requisite to a reliable system is a well-balanced distribution of power sources in relation to load centers.

To recapitulate, the selection of a power plant site must take into account all of the factors enumerated above. In addition, such considerations as the economic effect of a particular local tax situation and the availability, productivity and cost of construction labor in the area must also be taken into account. Alternative locations, with consideration given to each of these factors, need to be investigated in detail and decisions made based on the most economical choice to supply the system's needs in the most reliable fashion while still meeting essential environmental requirements. Chapter X outlines one possible approach to meeting the region's power supply requirements through the year 1990.

Trends in Generation Technology

This discussion will dwell briefly on expected trends in generation technology, particularly as related to unit size and efficiency, plant size, and unit availability. The bulk of these comments will pertain to fossil-fired and nuclear-fueled generation, with brief reference to pumped-storage projects.

Fossil-Fired Generation

The economies of scale inherent in generating equipment have long been recognized in the East Central Region. Likewise, many developments to improve thermal efficiencies of coal-fired units were pioneered in this region. The Philo Unit No. 6 of Ohio Power Company (AEP) was the first full-scale prototype unit (107 MW) in the United States to utilize the once-through boiler concept at supercritical steam conditions (4,500 lbs./sq. in. pressure and 1,150° F temperature). This unit, placed in operation in 1957, was followed by the first large commercial unit of this type (450 MW) at Breed Plant of Indiana & Michigan Electric Company (AEP). Today, the bulk of all new fossil-fired generation under construction or on order in the East Central Region is of large size and of the supercritical design. Chapter X impressively shows the accelerating trend to large units in the future.

Although little improvement in thermal efficiencies of fossil-fired units, over and above those already achieved (8,550 to 8,900 Btu per kilowatt-hour), can be anticipated in the foreseeable future, further capital cost economies are expected with increasing unit size. Further improvements in efficiency must await the development of new materials, capable of operating at still higher pressures and temperatures and available at reasonable cost. No breakthrough in metallurgy in this regard is in sight at the present time. Future economies must depend, therefore, essentially on increases in size.

Unit sizes of 600 to 800 megawatts are now in operation in the East Central Region and units of 1,300-megawatt size are on order. A survey of utilities in the region indicates anticipated single unit sizes of 1,500 megawatts by 1980 and 2,500 megawatts by 1990. Most recent projections indicate possible unit sizes as great as 2,800 megawatts during this period. The achievement of economies of scale has been a significant factor in enabling the power industry to keep rates to consumers low notwithstanding the inflation that has been taking place.

While it has been generally assumed, and with some justification, that forced outage rates of coal-fired units will increase with size, based on the greater physical dimensions of such components as boiler tubes and their exposure to failure, experience to date with mature units of large size has been insufficient to draw statistically valid conclusions. The degree of reserve built into the many component parts of a large boiler-turbine-generator and

the design tolerances assumed, together with the preventive maintenance practices of the utility and the quality of the fuel used, will have a significant effect on forced outage experience. Initial periods of difficulty are characteristic of all new engineering design, particularly when it involves significant departure from the past, as in the case of supercritical units. Hence, any attempts at statistical correlation are complicated not only by large-size units but also by radically different steam conditions and, oftentimes, different operating practices. It is expected that future units of large size and of the supercritical design will show improved availability performance over those presently in existence or now coming into operation.

Nuclear-Fueled Generation

The ability to achieve economies of scale similarly applies to nuclear generation. In nuclear plants the equipment or facilities least affected by size, and therefore promising substantial economies of scale, include the reactor vessel, the safety injection system, buildings, control room, waste disposal, instrumentation, and other such items. The capital cost economies in going from an 800-megawatt size to an 1,100-megawatt size have been well established. While unit sizes beyond 1,100 megawatts will require additional study and equipment development, there is every reason to expect that economies of scale will continue to be available.

The thermal efficiencies of typical nuclear units now under construction are in the order of 10,500 Btu per kilowatt hour. Any real breakthrough in efficiency beyond this value must await the development of a high-temperature, high-pressure reactor.

The forced outage rates of large nuclear units have yet to be established. Because of their more conservative steam conditions (in the order of 750 lbs. per sq. in. and 500° F temperature), their forced outage rates resulting from turbine and steam generator component failure are expected to be less than those for comparably-sized coal-fired units. The need to allow time for refueling, however, and the possible inability to carry out all maintenance during such refueling periods, may well result in an overall unit availability rate comparable to that of coal-fired units. For this reason many utilities are assuming equal availability performance for both conventional and nuclear generating units in projecting their future capacity needs.

Plant Sizes

The need to utilize the limited number of plant sites most efficiently as well as to obtain the inherent economies, both in capital and in operating costs, will result in the development of very large power plants in the future. The largest coal-fired power plant in operation at this time in the East Central Region is 1,888,000 kilowatts. Several plants in the order of 2 million kilowatts are under construction and one plant of 2.9 million kilowatts has been committed. Power plant sizes up to 4 million kilowatts are projected for the 1970's. Indications are that plants of this and even larger size will become increasingly prevalent in the years ahead.

Nuclear-fueled plants in sizes up to 2.2 million kilowatts are already under construction in the region. It is reasonable to predict nuclear plants of up to 3-4 million kilowatts in the future. One constraint on size of power plants may be the size of investment committed to one location. For plants of 4 million kilowatts this may amount to 600-800 million dollars. The consequences of damage and the undesirability of concentrating such investments, particularly as regards nuclear, may become a limiting factor. Another constraint is that plant sizes must be in balance with the other elements of the bulk power system that affect reliability of power supply.

Pumped Storage Plants

The efficient and economic development of pumped storage plants so as to utilize the water resources of a river system or other body of water may require, in many instances, the development of plants of very large capacity. In the East Central Region, the two plants of 1,800-megawatt size, now projected, are examples of such developments. Selection of very large size for future pumped storage projects may also be the only way to assume the increasingly heavy economic burdens of water quality control storage, flood storage, and recreation, as required by federal agencies for plants of this type.

The desirability of using the largest possible generating units in such projects presents a continuing technological challenge to assure satisfactory performance in both generating and pumping modes.

The benefits of pumped storage plants in terms of their lower equipment and outage rates and their rapid response as spinning reserve during periods of sudden system disturbances are important considerations.

CHAPTER V

TRANSMISSION AND INTERCONNECTION

Introduction

This chapter describes the present status of transmission in the East Central Region and of interconnections within the region and with contiguous regions; discusses briefly the broad planning considerations that led to the evolution of the present, highly developed transmission network; and reviews, in general terms, the direction in which transmission and interconnection within the region can be expected to develop in the future.

As described elsewhere in this report, the East Central Region—while covering less than 7% of the land area of the United States—represents one of the most highly developed areas of the country. It is not surprising, therefore, that in terms of electric power supply this region is one of the most dynamic areas in the nation.

The electric power demand in the East Central Region, as discussed in Chapter II, is widely distributed. Even the largest load concentrations around the major metropolitan areas within the region, such as Detroit, Cleveland, Pittsburgh, Louisville, Indianapolis, and several others, are themselves rather widely distributed geographically. Likewise, the generating plants within the region are widely distributed, even though there is a somewhat greater concentration of generation in the eastern part of the region and along the Ohio River than elsewhere, because of easier access to an economical coal supply.

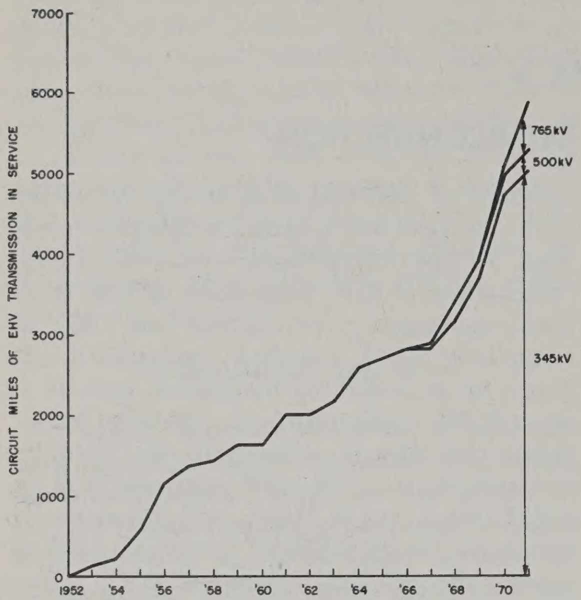
Present Status

Partly because of the wide geographical dispersion of both electric power demand and generation, the East Central Region does not have a pattern of transmission development that is primarily dictated by energy transportation requirements, as is the case in many other areas of the country. Rather, the transmission network is characterized by its extensive coverage of the entire area and by the multitude of interconnections among the systems within the region and to systems in contiguous areas. Thus, the East Central Region contains the highest concentration of EHV transmission facilities in the world, aggregating in 1968 to more than 3,900 circuit-miles of 345-kV and 500-kV transmission, supported by an underlying transmission network of about 22,000 circuit-miles in the 120-kV to 230-kV voltage class. Also, it represents the most highly interconnected area in the world containing, as of the end of 1968, a total of 79 high-voltage interconnections in the 138-kV to 500-kV voltage range linking together the individual systems within the region, as well as 49 additional interconnections at 110 kV to 500 kV connecting the East Central Region to adjacent areas.

Today's highly developed transmission network in the East Central Region is the result of many years of pioneering effort, cooperation, and joint study among the bulk power supply systems within the area. These systems recognized for many years the importance of strong transmission channels tieing together the major load areas and generating sources. Thus, the first high-voltage transmission line in the United States, at 138 kV, was built in the East Central Region in 1917, from Windsor Plant on the Ohio River to the Canton-Akron, Ohio area. The first EHV transmission line in the country was introduced in this region in 1952, as a 50 mile, 345-kV line from the Philip Sporn Plant to the Kanawha River Plant of the American Electric Power (AEP) System. In May 1969, the highest EHV transmission line in the world was energized in this region by the placement in commercial operation of the first link of an extensive, 1,100-mile, 765-kV network.

Exhibit V.1 shows the growth of EHV transmission in the East Central Region between 1951 and 1968, involving significant extension at 345 kV throughout the area and, beginning in 1966, the introduction of 500 kV in the eastern part of the region in close coordination with the 500-kV de-

EXHIBIT V.1
EAST CENTRAL REGION
DEVELOPMENT OF EHV TRANSMISSION
1951– 1970



velopments on the PJM and Virginia Electric and Power Company (VEPCO) systems.

While there have been instances within the East Central Region when EHV transmission lines were utilized, for a time, for purely energy transportation purposes from a "mine mouth" plant to a load center—as in the case of AEP's Breed Plant, Ohio Edison's Sammis Plant, and Indianapolis Power & Light's Petersburg Plant—such transmission lines, in due course, invariably were incorporated into the overall EHV network overlaying the entire area. This is in accord with the basic planning philosophy of the bulk power supply systems within the region, calling for the development of a strong, flexible, and multi-purpose transmission network. It affords the achievement of a very high level of reliability of bulk power supply at a reasonable cost while at the same time offering opportunities for substantial economies through a variety of power interchange transactions.

This planning philosophy is also reflected in the extent to which the power systems within the East Central Region are continuing to build transmission facilities to meet the growing demand for electric power and energy. While the tentative plans for transmission additions within the region, for the periods 1971–1980 and 1981–1990, are discussed in some detail in Chapter X of this report, it is of interest to note here the extent of transmission construction now actually underway or authorized. A total of 4,400 circuit-miles of new EHV transmission facilities is now authorized or under construction within the region and is scheduled for completion during the 1969–1973 period. This includes 1,100 circuit-miles at 765 kV and 3,300 circuit-miles at 345 kV and 500 kV. In addition, 1,500 circuit-miles of new transmission facilities in the 120-kV to 230-kV voltage class are authorized or under construction. The power systems of the East Central Region have also authorized or have under construction 33 new high-voltage interconnections within the region (28 interconnections at 345 kV and five at 138 kV), as well as five new interconnections between the East Central Region and adjacent areas (one at 765 kV, three at 500 kV, and one at 345 kV).

The Long-Term Outlook

In contemplating the long-term development of EHV transmission and interconnection in the East Central Region, it is important to consider the basic technological, economic, and social factors which contributed most to its past and present development. It is also essential to review the long-term trends in such factors and to explore the implications of these, and any other, trends that may be on the horizon.

The more important factors that have influenced the past and present development of EHV transmission in the East Central Region and elsewhere can be summarized briefly as follows:

Load Growth

It stimulated the search for the most effective and economical means of transmitting the additional amounts of electric power and energy from the generating sources to the load centers.

EHV Transmission Economics

These are predicated on the basic fact that the capability of a transmission circuit increases approximately as the square of its rated voltage. If, through research and technological improvements, a transmission circuit can be built for higher rated voltages at a cost that increases less in relation to the increases in its transmission capability, then the higher voltage transmission becomes intrinsically

more economical. Its introduction on a given power system becomes then a matter of timing and depends in each instance on specific conditions, such as transmission distance, transmission capability requirements, and network configuration.

Generating Capacity Economics

The technical feasibility and economic attractiveness of concentrating increasingly large blocks of generating capacity in single units and plants created opportunities for similar concentration of transmission capability in a single transmission channel.

Limited Availability of Land and Rights-of-Way

EHV transmission enables a much greater utilization of a given right-of-way in terms of load-carrying capability.

Reliability Considerations

One of the basic prerequisites to reliable bulk power system design is the need to maintain proper balance among various system elements, such as the size of its generating units and plants, strength of its interconnections, and capability of its internal transmission channels. Thus, the trend toward economies of scale in generation implies the need for corresponding reinforcements in transmission.

Interconnections

The trend toward larger generating unit and plant sizes increases greatly the opportunities for interconnection benefits in terms of reductions in installed generation reserves, carrying out of interconnection transactions of various kinds, and enhancement of transmission system reliability.

Looking into the future, it appears certain that electric power demand in the East Central Region will continue to increase during the next 20 years at an essentially undiminished rate. It is evident, therefore, that further development of transmission and interconnections in the East Central Region will continue to play a vital and indispensable role in the years ahead. Considerations of growth in demand, scarcity of rights-of-way, reliability requirements, generating capacity economics and interconnection benefits, all point toward further expansion of 345 kV, 500 kV, and 765 kV transmission within the region, as well as toward the introduction of an even higher voltage overlay—at an ultra-high voltage in the 1,200–1,500-kV range—by the middle or late 1980's. While the generation and transmission patterns for the East Central Region, presented in Chapter X of this report for the 1981–1990 period, do not show a higher-voltage overlay on the then existing 765-kV network, the need for such an overlay within the region by that time period is a distinct possibility.

CHAPTER VI

GENERATION RESERVES

The analysis and determination of generating capacity reserve requirements for a power system constitutes one of the most important system planning functions. Great emphasis has been placed, especially in recent years, on the need for performing reserve studies in order to evaluate the adequacy of installed capacity to meet system load requirements.

Generation Reserve Methods

The generation reserve planning techniques which have been used by utility systems within the East Central Region, as in other areas of the country, can generally be divided into two broad categories:

(a) Non-probabilistic methods.

(b) Probabilistic methods.

Generating capacity requirements based on non-probabilistic methods have generally been determined by establishing minimum reserve requirements over the annual peak load period based on:

(a) A fixed minimum percentage of peak load, or

(b) A fixed multiple of the system's largest generating unit, as for example the largest unit plus a mode unit.

In the use of these non-probabilistic methods, judgment plays a predominant role. Their principal advantage is simplicity since reserve requirements can easily be calculated once an annual peak load has been projected or the size of the largest unit is known. This simplicity of application, however, is offset by the inherent inability of such methods to measure, in a quantitative manner, the reliability associated with generating capacity being able to meet system load on a day-to-day basis. In this approach consideration is not given to the daily, monthly, and seasonal load patterns, nor to the characteristics of generating equipment peculiar to the individual system such as the mix of unit types and sizes, and unit availabilities. The size of the largest unit is recognized to some extent, of course, when such a unit is used as the basis for determining the reserve requirement at the time of annual peak load. This reserve requirement might also reflect any planned maintenance needs anticipated for the time of peak load.

Probabilistic methods, on the other hand, although somewhat complex, do provide the only analytical means for evaluating the risk associated with supplying system load requirements. This is generally accomplished by interrelating load and capacity models developed for the particular system and time period under study. The load model usually consists of a series of load levels representing the full range of daily or monthly peak loads anticipated throughout the given period. It may also include provision for the probability of load changes because of deviations from projected normal conditions of weather or economic activity.

The capacity models used in probabilistic methods usually involve calculating the likelihood of occurrence of various levels of available system generating capacity, based on assumed forced-outage rates for the individual units, and taking into account outages for scheduled maintenance. The interrelation of such capacity models with the load models previously described forms the basis for evaluating the risk associated with capacity not being able to satisfy the load requirements.

Discussion of ECAR Reserve Studies

Inasmuch as the power systems making up ECAR supply about 95% of the electric energy requirements in the East Central Region, the nature of future installed generating capacity reserves within the region will be greatly influenced by the capacity additions planned by these systems.

In accordance with its broad objective to assure reliability of overall bulk power supply, ECAR has

been carrying out extensive studies to develop a methodology for appraising the adequacy of installed generating capacity reserves among its member systems. These studies have verified the usefulness of employing probabilistic techniques when evaluating the reserve situations of a group of utilities with widely different load and capacity characteristics, such as exist within ECAR. On the basis of these studies, steps are underway to establish criteria for maintaining minimum generating capacity reserves applicable to all member systems.

A description of the basic features of an approach to evaluating generating capacity reserves, which has thus far been found to be most applicable to meeting the needs of ECAR, is given herein. Some of the concepts which follow are similar to those described in studies performed within the American Electric Power Service Corporation [1] and within the group of utilities comprising CAPCO,[2] a power pool within ECAR.

Concept of Daily Capacity Margin

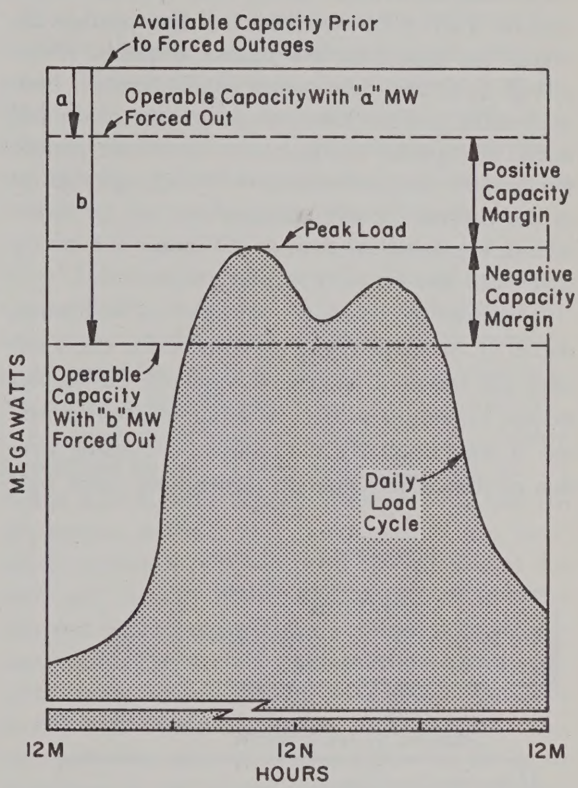
The basic unit of measurement by which a system can assess its relative reserve situation is the daily capacity margin. For the purposes of this report, the daily capacity margin is defined as the difference between total operable capacity on the system and the daily peak load. Operable capacity is considered to be the seasonally adjusted system generating capacity, including firm purchases and excluding all capacity deratings as well as planned and forced outages, at the time of daily peak load.

As can be seen from the illustration in Exhibit VI.1, the daily capacity margin can be either positive, negative, or zero, depending upon the relative magnitudes of capacity and load. Thus, when available capacity exceeds the daily peak load, a capacity surplus exists. Otherwise, when available capacity is less than the daily peak load, a capacity deficiency occurs.

It is important to note that a capacity deficiency does not necessarily mean loss of load, but, rather, defines the extent of dependence on the various supplemental capacity resources available to the system.

EXHIBIT VI.1

DERIVATION OF THE DAILY CAPACITY MARGIN



These supplemental capacity resources can come either from within the system, such as interruptible load curtailments, or from sources outside the system, such as emergency support from interconnections. Actual loss of load occurs, of course, only when the capacity deficiency exceeds the amount of supplemental capacity resources available at the time of deficiency.

The daily capacity margin normally varies from day to day, depending upon the magnitude of the load and the aggregate amount of planned and forced generating unit outages on the system. These margins can vary widely, even within 1 week, as shown in the hypothetical load-capacity situation of Exhibit VI.2. It can be seen from this exhibit that, for the 5 days indicated, 3 days show capacity surpluses while 2 days have capacity deficiencies.

Accumulation of statistics on capacity margins for a given power system over a given period of time

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[1] G. S. Vassell, N. Tibberts, "An Approach to the Analysis of Generating Capacity Reserve Requirements," IEEE Transactions on Power Apparatus and Systems, Vol. PAS–84, No. 1, pp. 64–79, January 1965.

[2] L. Firestone, W. D. Masters, A. H. Monteith, "The CAPCO Group Probability Technique for Timing Capacity Additions and Allocation of Capacity Responsibility," pending publication—IEEE paper No. 68TP693–TWR.

provides a means of appraising the relative performance of the system in supplying load throughout the entire period. As an example, the collection of capacity-margin data for a particular period, such as a year, can be arranged to form a frequency distribution plot in the manner shown in Exhibit VI.3. The same data can also be expressed by the corresponding cumulative distribution curve shown in Exhibit VI.4. Such distribution curves provide the means for describing the reserve situation of the system in several dimensions, i.e., in terms of both magnitude and frequency of occurrence of the full range of capacity margins over the entire period. From these distribution curves the aggregate effect of the various capacity margins can also be determined, expressed in terms of MW-days of capacity deficiency and capacity surplus, respectively.

As previously noted, the negative, or deficiency, region of the capacity-margin distribution curve defines the extent of system dependence on supplemental capacity resources in order to avoid actual loss of load. Similarly, the positive, or surplus, portion of the capacity-margin distribution curve represents the degree to which the system can supply help to its neighbors.

EXHIBIT VI.3

FREQUENCY DISTRIBUTION OF DAILY CAPACITY MARGINS FOR A TYPICAL YEAR

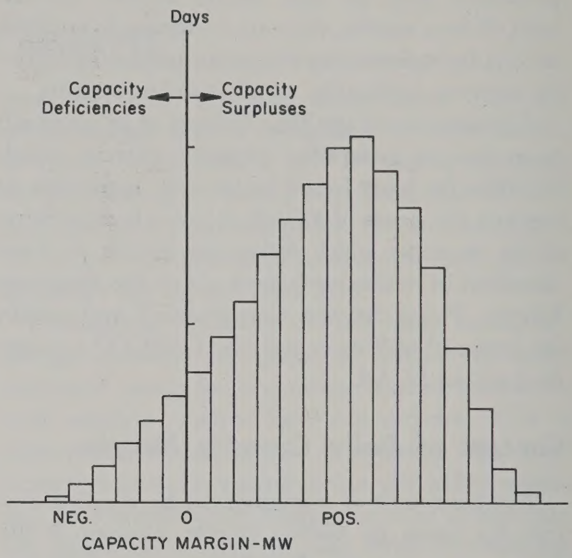
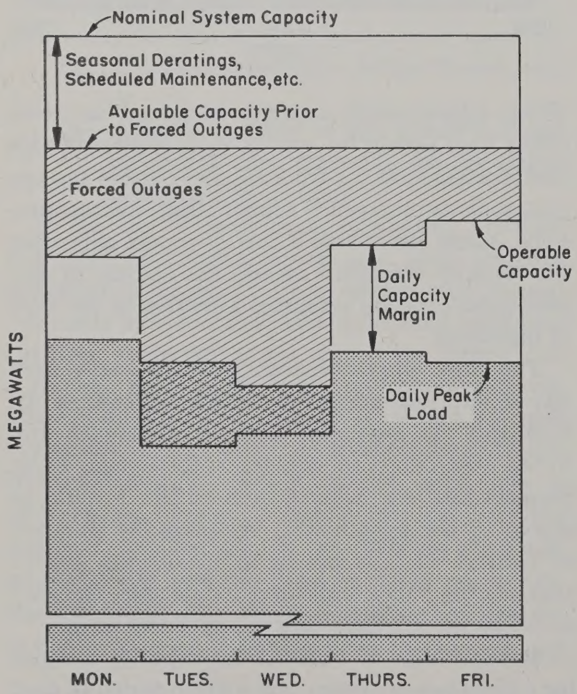


EXHIBIT VI.2

VARIATION OF DAILY CAPACITY MARGINS FOR A TYPICAL WEEK



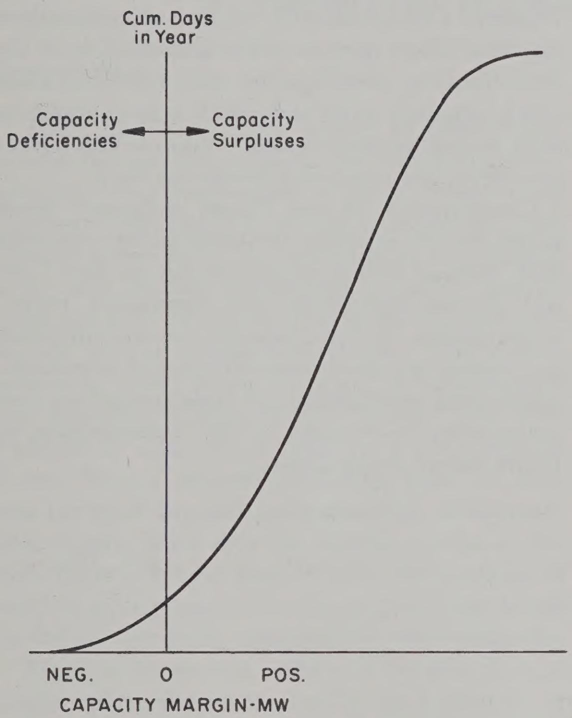
In view of the above, it is important, when evaluating the adequacy of a system's capacity reserves, to recognize the need for a realistic appraisal of the availability of all supplemental capacity resources, both internal and external to the system. This becomes especially significant when dealing with interconnected systems in which the amount of available interconnection support is a function of neighboring systems' reserve situations, the degree of interaction among the systems, and the limitations imposed by interconnection transmission capabilities.

Based on the concepts just described, annual capacity-margin distribution curves can be developed for a given power system for any future year by properly interrelating projected capacity and daily peak loads, taking into account the entire range of possible forced outages, using probability theory. Once such curves are developed, they become very powerful tools in the evaluation of future capacity reserve requirements.

Studies within ECAR have ascertained the practicality of using the concept of "Capacity-Margin Distribution" as a basic analytical tool for apprais-

EXHIBIT VI.4

CUMULATIVE DISTRIBUTION OF DAILY CAPACITY MARGINS FOR A TYPICAL YEAR



ing the adequacy of system reserves. The method is comprehensive in scope because it enables consideration not only of the annual peak load, but also the load's daily, monthly, and seasonal characteristics as well. Similarly, recognition can be given to all the important attributes of capacity, including unit size, forced-outage performance, maintenance requirements and seasonal limitations.

The approach, furthermore, provides a meaningful basis for comparing the results of actual day-by-day performance of a system with calculations of its predicted performance. Such comparison provides a means for developing confidence in the validity of the method.

Factors Affecting Future Reserve Requirements

A method of evaluating reserves, such as described above, provides a valid analytical tool which is mathematically rigorous and which could, therefore, serve as a sound basis for the engineering evaluation of system reserve requirements. However, the availability of such tools does not assure meaningful results unless meaningful data are used, including the necessary projections and assumptions. Judgment, therefore, becomes a major factor in the determination of future reserve requirements.

It is judgment that establishes the basis for the input projections and assumptions for any reserve study. These projections and assumptions must be made in a number of areas, including system load growth and forced outage performance of generating capacity. Likewise, judgment must be used in evaluating the results of any reserve study. Consideration must be given to such factors as the possibility of slippage in the in-service date of new generating units, availability of supplemental capacity resources, and the extent to which provision needs to be made for actual conditions several years into the future being different from existing conditions.

Although no attempt was made by the Advisory Committee to project reserve requirements, per se, in the East Central Region through 1990, the independent analyses and judgments of the individual utilities and power pools are reflected in the load and capacity assumptions contained in other chapters of the report. These plans result in reserve margins for the overall region that amount to approximately 20% of annual peak load. This tends to reflect an increased concern with the need to assure adequate reserves to meet projected loads, an awareness of the serious consequences of not having sufficient capacity to meet the load, and careful consideration of assumptions with regard to several significant factors affecting installed capacity reserves. Some of these factors are discussed below:

Generating unit size has a significant effect on system reserve requirements. Larger unit sizes, when related to a given system size, inherently require larger reserves in order to meet a given standard of reliability. The increased trend toward larger unit sizes within the East Central Region, as indicated in Chapter X; the higher forced outage rates associated with such units during their initial years of service before reaching maturity and before necessary design modifications and improvements have been incorporated into subsequent units of any given series; and the lack of sufficient operating data on large units, in general, make predictions of unit outage performance relatively uncertain. Therefore, sufficient reserves must be provided,

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when planning future capacity requirements, to reflect conservative projections of forced-outage rates of new units.

An increasingly higher percentage of the new capacity to be installed within the East Central Region in the future will be in the form of nuclear units, generally of large size. The very limited operating experience on such units to date adds to the uncertainty of projecting their outage performance and operating constraints.

The forecasting of load can also involve a considerable degree of uncertainty. Sufficient provision needs to be made in the load forecast, not only for departure from, say, the normal long-range economic cycle, but also for the likelihood of occurrence of extremes in weather. In particular, the rapid growth of temperature-sensitive loads in the East Central Region has contributed directly to increasing seasonal peak loads and the reserve requirements estimated for the future.

Of increasing significance in recent years with regard to generating capacity reserves is the matter of slippage of in-service dates for new generating units. This has been particularly evident in the case of nuclear units. Recent experiences with equipment troubles, construction delays, and manpower problems have dramatically illustrated the importance of providing for increased lead times when planning future capacity requirements. Provision for such slippage of in-service dates must, therefore, be allowed for in reserves planning.

As previously pointed out, the indicated future reserve requirements for the East Central Region represent a composite of a number of independent forecasts. These reserves reflect a recognition of the limitations in coordination and communication which presently exist and which may continue to exist among the independent entities within the region when operating on a day-to-day basis.

Consideration of the factors indicated above points to the necessity for maintaining relatively high levels of system reserves within the East Central Region throughout the foreseeable future. These factors, in large measure, are uncontrollable and, hence, require a reasonable degree of conservatism when establishing the basic projections and assumptions to be used in the determination of future reserve requirements.

CHAPTER VII

COORDINATED PLANNING AND DEVELOPMENT

Introduction

There has been a long history of coordination among the electric utilities in the East Central Region involving every aspect of power system planning and operation. The earliest example of a joint venture in ownership and operation of a generating plant and related transmission occurred over 50 years ago with the construction of the Windsor generating station on the Ohio River. This station, owned by Ohio Power Company, a subsidiary of the American Electric Power System, and West Penn Power Company, a subsidiary of the Allegheny Power System, utilized generating units of large size for their day and an economical mine-mouth coal supply. Since then the electric utilities in the East Central Region have been in the forefront of technology in generation in terms of unit size as well as turbine pressures, temperatures and efficiencies.

Many of the electric utilities in the East Central Region pioneered in developing the techniques of interconnected system operation in the 1920's. Since then there has been extensive development of the transmission systems of these utilities, the interconnections between them, and interconnections with systems outside the East Central Region. These developments have created the most tightly interconnected transmission system in the world, initially at 138 kV and more recently at 345 kV and 500 kV. Both these latter transmission voltages have been and will be extended, together with 765 kV in the near future, on a coordinated basis to meet the region's needs.

Also, since the early 1920's joint planning and operating studies have been carried out on a regular basis by combinations of two or more of the electric systems in the East Central Region to attain economies and to augment bulk system reliability. Similar planning and operating studies have been made with systems outside the region such as those of the PJM Interconnection. the Carolina-Virginia companies, the Illinois-Missouri companies, the Tennessee Valley Authority, and the Hydro Electric Power Commission of Ontario (Ontario Hydro).

Against this historical background of coordination by the electric systems in the East Central Region, this chapter discusses the present structure of the industry in the region and developments in coordination, both intraregional and interregional, for purposes of reliability and economy.

Coordination—Defined

Definitions of the terms "coordination" and "full coordination" are essential to assure an understanding of their usage in this report since such terms or concepts have no standard meaning in the electric utility industry and among regulatory agencies.

"Coordination," as used in the body of this report, means any joint action taken by two or more electric utility systems, each of which is a separate entity, to achieve desirable and useful objectives which they cannot readily obtain independently. This definition is to be contrasted with that contained in the FPC guidelines, dated 2/21/67, and distributed to the Regional Committees, which state that coordination is, ". . . joint planning and operation of transmission and generation by two or more electric systems for improved reliability and increased efficiency to take advantage of opportunities which would not be attainable if each system acted independently." The guidelines' definition of coordination is not used in this report because it calls for (a) joint planning of (1) transmission and (2) generation, and (b) joint operation of (1) transmission and (2) generation, whereas coordination as used in the industry and in this report, as defined above, could involve any of these four items or any combination of them.

"Full coordination," as defined in the FPC guidelines, and as used in this report, ". . . is the means by which all systems within a region, to the extent technologically and economically feasible, have available to them the opportunity to achieve in-

creased power supply reliability and optimum economy by jointly planning and operating the combined resources of these systems to serve the combined loads and by exploiting all opportunities for coordination with adjacent regions."

Structure of the Electric Power Industry in the East Central Region

The East Central Region includes all or portions of nine states encompassing western Pennsylvania, western Maryland, a northern portion and the western part of Virginia, all of West Virginia, Ohio, and Indiana, the lower peninsula of Michigan, most of Kentucky, and a small part of northeastern Tennessee. This area contains about 32 million people and is a highly productive part of the United States and one which is greatly diversified in population, resources, and industry. As indicated in Chapter I, although the region covers only about 7% of the land area of the United States, it utilizes over 17% of the nation's electric energy.

Exhibits VII.1 and VII.2, which follow, are based on data supplied by the Chicago Regional Office of the FPC and show the structure of the industry in this region by number, size, and type of ownership of utility systems and whether or not such systems have generation, are interconnected or are members of the East Central Area Reliability Coordination Agreement (ECAR), described in detail later in this report. The number of electric systems shown in these two exhibits and their various classifications represent their status as of the end of 1967 whereas the data on size (peak loads in MW and energy in MWh) are as of the end of 1965.

Exhibit VII.2 also sets forth pertinent load and capacity data for the electric systems in the East Central Region. This shows that of the 401 systems having a total annual non-coincident load of 34,249 MW in 1965, the 19 electric systems included in ECAR had an annual non-coincident peak load of 31,114 MW (about 90% of total) while the 382 non-ECAR systems had an annual non-coincident peak load of 3,135 MW (about 10% of total).

The Energy for Load data in Exhibit VII.2 is reported only for the larger systems which file data on FPC Form 12. Hence, no Energy for Load data appears in the table for the smaller systems. The difference between the Energy for System and Energy for Load columns is that Energy for System represents the energy requirements of the electric system only, whereas Energy for Load includes energy delivered by the larger systems to the smaller.

The annual system peak load data likewise includes power delivered to the smaller systems by the major ones. Hence, since both the larger and smaller systems report the same power as part of their system peak, duplication results and the total non-coincident peak is greater than the actual regional peak. These data are shown in this matter so that the relative sizes of the systems can be ascertained.

EXHIBIT VII.1

East Central Region—Number of Electric Systems by Size (1965) and Ownership (1967)

System peak load (MW)	Number of Municipals [1]	Number of REC's	Number of investor owned	Total
6,400–10,000				
3,200– 6,399			2	2
1,600– 3,199			4	4
800– 1,599			9	9
400– 799			2	2
200– 399	1		1	2
100– 199	2	1		3
50– 99	5			5
25– 49	7	3	1	11
13– 24	26	29	1	56
0– 12	214	74	19	307
Total....	255	107	39	401

[1] Includes state colleges.

Recent Developments in the East Central Region Regarding Coordination for Reliability and Economy

The following relatively recent events have had significant effects on coordination in the East Central Region:

1. ECAR organized;
2. Central Area Power Coordination group (CAPCO) reorganized;
3. Indiana Pool expanded to Kentucky-Indiana Pool (KIP);
4. Buckeye Project;
5. Mergers and acquisitions.

ECAR Organized

On January 14, 1967, the following 23 electric utilities whose systems are directly or indirectly interconnected signed the East Central Area Reliability Coordination Agreement: Appalachian Power Company, The Cincinnati Gas & Electric

EXHIBIT VII.2

Inventory of East Central Region Electric Systems (Systems' Status Dec. 31, 1967; Data as of Dec. 31, 1965)

System status	Number of systems	Energy for system (MWH)	Energy for load [1] (MWH)	Annual system peak [2] (MW)	Installed generating capacity (MW)
In ECAR:					
Investor owned	18	176, 972, 744	182, 826, 772	30, 919	35, 172
REA financed	1	58, 000	901, 100	195	318
Total in ECAR	19	177, 030, 744	183, 727, 872	31, 114	35, 490
Not in ECAR:					
Municipals: [3]					
Isolated	27	1, 412, 523	1, 301, 037	293	473
Interconnected:					
Without generator	169	2, 251, 882	....	529	XXX
With own generator	59	5, 877, 727	5, 352, 542	1, 171	1, 576
Total municipals	255	9, 542, 132	6, 653, 579	1, 993	2, 049
REC's:					
Isolated	....	....	....	....	....
Interconnected:					
Without generator	103	4, 429, 082	....	1, 014	XXX
With own generator	3	62, 320	341, 481	80	61
Total REC's	106	4, 491, 402	341, 481	1, 094	61
Investor Owned:					
Isolated	[4] 1	6, 238	....	1	....
Interconnected:					
Without generator	14	86, 367	....	17	XXX
With own generator	6	149, 078	148, 969	30	19
Total investor owned	21	241, 683	148, 969	48	19
Total not in ECAR	382	14, 275, 217	7, 144, 029	3, 135	2, 129
Grand total	401	191, 305, 961	190, 871, 901	34, 249	37, 619

[1] Only systems which file FPC Form 12 report.

[2] Non-coincident peak, including power reported in major systems' peak which is delivered to small systems and therefore duplicated in small systems' reported peak.

[3] Includes state colleges.

[4] Supplied by industrial concerns.

Company, The Cleveland Electric Illuminating Company, Columbus and Southern Ohio Electric Company, Th Dayton Power and Light Company, Duquesne Light Company, Indiana & Michigan Electric Company, Indiana-Kentucky Electric Corporation, Indianapolis Power & Light Company, Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Northern Indiana Public Service Company, Ohio Edison Company, Ohio Power Company, Ohio Valley Electric Corporation, Pennsylvania Power Company, The Potomac Edison Company, Public Service Company of Indiana, Inc., Southern Indiana Gas and Electric Company, The Toledo Edison Company, and West Penn Power Company. Subsequently, East Kentucky Rural Electric Cooperative, Consumers Power Company, and The Detroit Edison Company became parties to the ECAR Agreement, so that ECAR now consists of 26 electric utilities (19 power

systems) in the East Central Region with a total installed generating capability in excess of 40 million kilowatts as of December 31, 1967.

The organization and duties of the Executive Board, Coordination Review Committee, Advisory Panels, and the Executive Manager are set forth in the ECAR Agreement dated August 1, 1967, and Supplemental Agreement dated October 20, 1967 (Appendix VII–A). The ECAR Agreement was the result of efforts, during 1966, of members of the original CAPCO Group who saw the need for an organization whose sole purpose would be to further augment bulk power supply reliability of the electric systems in the East Central Region. The Federal Power Commission and staff have been kept informed of the organization, objectives, and progress of ECAR through discussions with representatives of the ECAR organization. The effect of ECAR on the enhancement of reliability of bulk power supply within the East Central Region is discussed in a subsequent part of this chapter concerning the goals of the power industry in the East Central Region, as well as in Chapter VIII of this report.

CAPCO Reorganized

On February 1, 1967, certain of the participating members of the original, informal Central Area Coordination Group (CAPCO) withdrew, thereby reducing the membership to five companies, namely, The Cleveland Electric Illuminating Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company and The Toledo Edison Company.

On September 14, 1967, these five companies signed a Memorandum of Understanding to coordinate the installation of generating capacity on the systems of the parties to: (1) further the reliability of bulk power supply through assurance of an adequate reserve generating capacity level with reserve capacity coordination, (2) attain maximum economy, consistent with such reliability, by taking advantage of the economies of scale which will be available, (3) share the resulting responsibilities and benefits on an equitable basis, and (4) provide a means for more effective coordination with other power pools and coordination groups. This arrangement is discussed further in the portion of this chapter concerning reliability and economics.

KIP Established

On May 31, 1967, a letter of intent was signed to create the Kentucky-Indiana Pool (KIP) by expansion of the Indiana Pool, comprised of Public Service Company of Indiana, Inc., and Indianapolis Power & Light Company, to include the Kentucky Utilities Company. The Indiana Pool had been formed on April 30, 1964, with actual sharing of capacity commencing on May 1, 1967. The formal agreement to include Kentucky Utilities was signed on September 5, 1968. The Kentucky-Indiana Pool will commence to share capacity and coordinate operations on May 1, 1970, while carrying on planning activities in the interim. The pool is designed to assure greater reliability of service and added economy in operation.

Buckeye Project

In June 1968 Buckeye Power, Inc., an organization of 27 rural electric cooperatives in the State of Ohio, purchased one of the two 615-MW generating units at the Cardinal Plant from the Ohio Power Company. The 27 cooperatives receive their power from this unit through approximately 180 delivery points from the systems of the following electric utilities in Ohio: The Cincinnati Gas & Electric Company, Columbus and Southern Ohio Electric Company, The Dayton Power and Light Company, Monongahela Power Company, Ohio Power Company, and The Toledo Edison Company. Seven of the cooperatives now being served by Ohio Edison Company will, commencing August 1970, purchase their power requirements from Ohio Power Company at the existing delivery points between Ohio Edison and the cooperatives (and any additional delivery points provided for in the future). For this purpose Ohio Edison will purchase power from Ohio Power and sell the power required to serve the cooperatives to Ohio Power at such delivery points.

Acquisitions and Mergers

The historical development of the vast majority of power systems shows that they are the result of consolidations and mergers. These are the power systems whose consumers today realize the economic benefits of size. Exhibit VII.3, which comprises a tabulation of acquisitions and mergers in the East Central Region for the 5-year period 1964 through

EXHIBIT VII.3

East Central Region Acquisitions and Mergers (1964–68)

Name of system acquiring	Name of system acquired or merged	Date of event	Number of customers involved
APS, Inc.	Cumberland Valley Elec. Co.	1964	6, 180
	Ford City Borough Municipal Light Plant	1964	1, 800
	Stoufferstown Electric Co.	1965	157
	Borough of Brackenridge	1966	1, 740
	Borough of Tarentum	1966	2, 860
AEP Co.	City of Willard, Ohio	1965	2, 056
	Town of Albion, Ind.	1966	723
	Village of Paulding, Ohio	1966	1, 256
	Town of Wheelwright, Ky.	1967	250
	Michigan Gas & Electric Co.	1967	22, 389
Consumers Pwr Co.	Rogers City Power Co.	1967	1, 523
Dayton P &L Co.	Bellefontaine Municipal Electric System	1965	4, 651
Duquesne Lt. Co.	Sharpsburg Borough Municipal System	1964	2, 130
	Borough of Aspinwall Municipal System	1966	1, 300
No. Ind. P.S. Co.	Nappanee Utilities Co.	1966	2, 343
Ohio Edison Co.	Lowellville Municipal System	1965	660
P.S. Indiana	Crothersville Municipal System	1964	641
	Rushville Municipal System	1967	3, 300
Toledo Ed. Co.	Stryker Municipal System	1963	495
	Clyde Municipal System	1965	1, 680

1968, inclusive, shows that these historical developments are continuing.

On January 22, 1968, American Electric Power Company announced an agreement covering the proposed acquisition of Columbus and Southern Ohio Electric Company through an exchange of common stock. Consummation of the agreement is subject to the approval of the Securities and Exchange Commission and other legal requirements.

On April 10, 1968, eight electric utilities in the East Central Region announced that they are studying the feasibility of the formation of a holding company and a corporation to provide centralized services for the resulting system. If and when such a plan has been formulated it will be subject to the approval of the SEC and other legal requirements. The companies participating in such studies are Cincinnati Gas & Electric Company, Cleveland Electric Illuminating Company, Dayton Power and Light Company, Duquesne Light Company, Ohio Edison Company, Pennsylvania Power Company, Toledo Edison Company, and Union Light, Heat and Power Company.

Summary of Recent Developments

The preceding developments involving ECAR, CAPCO, KIP, and Buckeye, as well as the acquisitions, mergers and other possible affiliations, show that the electric systems in the East Central Region are continuing, by various procedures and mechanisms, to improve coordination so as to assure greater reliability and attain further economies. The diversity of approach used in these various efforts is a recognition of the range and complexity of inter-system coordination and the fact that no one coordination mechanism or approach provides a universal solution. Specifically, it recognizes the need to separate reliability from economy on a regional basis and the ability to achieve available economies in specific undertakings by the joint participation of limited numbers of power supply entities.

Coordination for Reliability and Economy

The FPC guidelines of 2/21/67 state, "The efforts of various task forces and committees participating in the current updating of the National Power Survey are premised on the assumption that goals for such electrical coordination will be achieved by 1980. It is anticipated that the Regional Committees will explore and report upon the general nature and extent that the general goal of full coordination may be attained through existing and developing opportunities for coordinated planning of transmission, coordinated reserve generating capacity, co-

ordinated planning for the installation of optimum size generating units and coordinated operation of all installed facilities within each region as well as exploitation of all opportunities for inter-regional coordination."

"Full coordination," as previously defined, could not be attained on a regional basis by 1980, even if it were deemed to be the desired objective, because it would not be possible to work out the multitude of changes in existing contractual arrangements, develop the many necessary new contractual responsibilities on a basis equitable to all parties and implement the new arrangements. The great diversity in types of ownership of electric systems in the East Central Region, their extensive variation in size and their geographical spread make it exceedingly difficult to envision that regional joint planning and operation, as proposed by the FPC guidelines, could be successfully undertaken. Reliability and economy have been, are, and will continue to be essential goals in electric power system planning and operations. The realization of these objectives on a realistic basis can be achieved by all systems through existing and contemplated arrangements of the type already established without the wholesale application on a regional basis of the "full coordination" approach contemplated by the FPC guidelines.

In order to achieve reliability and economy for all systems within a region, an approach is needed that will break these goals down into manageable pieces by handling bulk power supply reliability on a regional basis and realizing economies by pooling and other contractual arrangements within subdivisions of the region. This should be a continuing process as the facilities of the electric systems in the region are increased to meet future requirements. This approach is consistent with the sentence on Page 2 of the FPC guidelines which states, "Goals for achieving substantial investment and operating economies on a regional basis should be so established as to give first consideration to maintaining bulk power supply reliability."

Bulk Power Supply Reliability for the East Central Region

The East Central Region constitutes an area of reasonable size (about 400 x 500 miles) and geographical boundaries within which to achieve maximum reliability of bulk power supply. The organizational arrangements and objectives set forth under the East Central Area Reliability Coordination Agreement (ECAR) will provide the means to achieve this reliability. Geographically the East Central Region is covered by parties to the ECAR Agreement whose systems are interconnected directly or indirectly. The 19 electric systems in ECAR furnish substantially all of the electric energy in this region. The 382 electric systems in the region not a part of ECAR had a 1965 estimated requirement of 14.3 billion kWh with an installed generating capacity of 2.1 million kW, whereas the energy supplied by the ECAR systems in 1965 was 177 billion kWh and the installed generating capacity was 35.5 million kW. A more detailed comparison is presented in Exhibit VII.2. The ECAR systems are strongly interconnected, having 79 interconnections at 138 kV or higher between members of ECAR and 38 interconnections at this voltage or above to systems in contiguous areas of Pennsylvania, Maryland, Virginia, North Carolina, Tennessee, Illinois and the Province of Ontario. These transmission facilities are operated at 138 kV, 161 kV, 230 kV, 345 kV, and 500 kV, with the initial segment of 765 kV just recently energized.

The ECAR policy-making body is its Executive Board, comprised generally of the chief executives of member systems. Under the Executive Board is the Coordination Review Committee, the technical right arm of the Executive Board, whose members are those having the responsibility for planning and/or operation of their respective electric systems.

Assisting the Coordination Review Committee are seven technical advisory panels, each consisting of seven members. These panels are concerned respectively with Transmission System Performance, Generation Reserves, Generation Facilities, Transmission Facilities, Protection, Operation, and Electrical Equipment. Panel membership is limited to seven to assure efficient working relationships in the carrying out of their assignments. Members are not selected to represent any specific systems or subareas of ECAR. They participate on the panels as representatives of the entire ECAR effort and their evaluation and recommendations represent what they consider to be in the best overall interest of ECAR.

As need arises the Advisory Panels appoint small working groups to carry out more detailed assignments. To facilitate communication with the panels, systems not represented appoint liaison contacts.

The Coordination Review Committee, in conjunction with each system, reviews and evaluates

such system's planning of its generation and transmission facilities and other matters relevant to the reliability of the ECAR companies' bulk power supply. This has to be done on a continuing basis.

The agreement provides for an Executive Manager. The Executive Manager has such staff as his requirements dictate. Presently his staff includes two engineers, two technicians, and three secretaries. These people are full-time employees of ECAR.

ECAR introduced in this region the concept of reviewing each system's plans sufficiently in advance of their implementation so as to permit their modification, if modification be required, to assure reliability of bulk power supply. If a determination is made that a given addition to, or modification of, existing facilities would jeopardize the reliable operation of the area as a whole, or any major part thereof, it is implicit that changes to make possible such reliable operation will be made in the design before the facility is built. Once the effect of proposed facilities on the reliability of ECAR's bulk power supply has been determined, it is believed that self-discipline will require a member, or group of members, to comply with the recommendations of ECAR.

Two points should be emphasized pertaining to matters with which ECAR is not now concerned nor plans to be concerned in the future.

The first is that ECAR does not maintain an around-the-clock, 7-days-a-week staff. Its job is not the running of the power systems but rather the carrying out of studies and investigations to establish principles and practices in order to assure adequate system performance in the future. The minute-by-minute operation of the systems remains in the hands of the present control and dispatching centers with only such daily assistance provided in the form of data on the area's overall status as to enhance reliable operation.

The second point is that ECAR is not a super-planning organization. It does not initiate plans, it reviews them solely from the standpoint of reliability of bulk power supply. Engineers most familiar with, and knowledgeable of, their respective system's power requirements do the actual planning. They are the most capable and best informed to do this task.

ECAR is an organization focused on the basic issue of reliable bulk power supply for the East Central Region. Its member systems have generation and transmission facilities that substantially affect the integrity of the bulk power supply, and have the technical resources and physical facilities which can make a contribution to the achievement of improved reliability within, and external to, the East Central Region. ECAR, by drawing upon the experience of its membership, has either developed, or is developing policies, procedures, and criteria that permit it to review the bulk power supply plans of its members, simulate ECAR systems' performance, coordinate maintenance, provide spinning reserve requirements for each system, and improve communication facilities between and among the systems.

Interregional Coordination

ECAR is one of the 12 major regional electric utility organizations which on June 1, 1968, established the National Electric Reliability Council (NERC). All classes of electric utilities, including federal, investor-owned rural electric cooperatives and municipal and state, are represented in the membership of the regional organizations constituting NERC.

Article 2 of the NERC agreement states its purpose:

> "2.01 The purpose of this Agreement is further to augment the reliability of bulk power supply in the electric utility systems of North America.
>
> To this end the Council will:
>
> (*a*) encourage and assist the development of interregional reliability arrangements among Regional Organizations or their members;
>
> (*b*) exchange information with respect to planning and operating matters relating to the reliability of bulk power supply;
>
> (*c*) review periodically regional and interregional activities on reliability;
>
> (*d*) provide independent reviews of interregional matters referred to it by a Regional Organization; and
>
> (*e*) provide information, where appropriate, to the Federal Power Commission and to other Federal agencies with respect to matters considered by the Council."

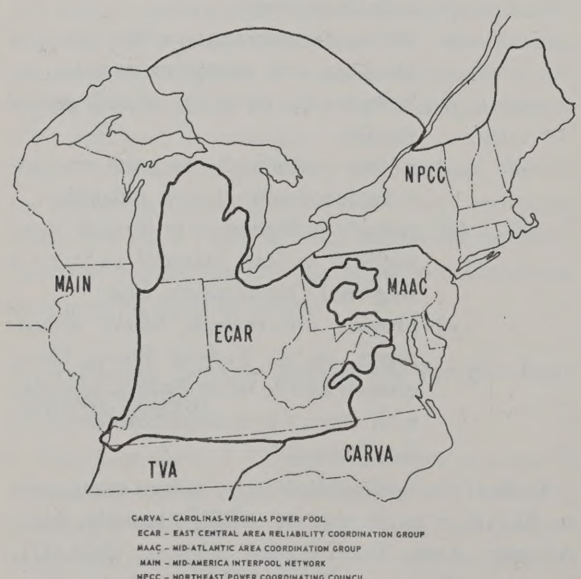
Each of the five regional organizations contiguous to ECAR is a member of NERC, namely, Mid-Atlantic Area Coordination Group (MAAC), Carolinas-Virginias Power Pool (CARVA), Ten-

nessee Valley Authority (TVA), Mid-America Interpool Network (MAIN), and Northeast Power Coordinating Council (NPCC).

Exhibit VII.4 shows that the East Central Region is bounded on the east by the Mid-Atlantic Area Coordination Group (MAAC) and the Carolinas-Virginias Power Pool (CARVA); on the south by CARVA and the Tennessee Valley Authority (TVA); on the west by the Mid-America Interpool Network (MAIN); and on the north by the Northeast Power Coordinating Council (NPCC). (The East Central Region is interconnected with Ontario Hydro, which in turn is a member of NPCC.)

Coordination by electric power systems within the East Central Region with systems in the above contiguous regions is one form of interregional coordination. A number of the utilities on the periphery of the East Central Region have interconnections and agreements with contiguous electric systems in these other coordination areas. These agreements provide for coordination of planning and operation of generation and transmission facilities to improve reliability and to effect economic and emergency power transactions. Some of these arrangements provide for standing committees, such as planning and operating committees, to carry out the intent of the contracts. On the eastern boundary of the East Central Region, Cleveland Electric Illuminating Company and Allegheny Power System have transmission facilities agreements with

EXHIBIT VII.4
EAST CENTRAL REGION AND
CONTIGUOUS COORDINATING GROUPS



CARVA – CAROLINAS-VIRGINIAS POWER POOL
ECAR – EAST CENTRAL AREA RELIABILITY COORDINATION GROUP
MAAC – MID-ATLANTIC AREA COORDINATION GROUP
MAIN – MID-AMERICA INTERPOOL NETWORK
NPCC – NORTHEAST POWER COORDINATING COUNCIL
TVA – TENNESSEE VALLEY AUTHORITY

certain utilities in the Pennsylvania-New Jersey-Maryland (PJM) Group and operating agreements with the PJM Group as a whole, and Allegheny Power System and Virginia Electric and Power Company have facilities and operating agreements. On the southern boundary of the region, the American Electric Power Company (AEP), Kentucky Utilities, Louisville Gas & Electric Company, and East Kentucky RECC have arrangements with TVA, and AEP has interconnection agreements with Virginia Electric and Power Company, Carolina Power and Light Company, Duke Power Company, and East Kentucky RECC; on the western boundary of the region, facilities and operating agreements exist between AEP and the Illinois-Missouri Companies (Ill-Mo), AEP and Commonwealth Edison Company, Public Service Company of Indiana and Ill-Mo, Kentucky Utilities and Ill-Mo, Kentucky Utilities and Electric Energy, Inc., and Northern Indiana Public Service Company and the Commonwealth Edison Company. The Michigan Companies (Consumers Power Co. and Detroit Edison Co.) have an agreement with Ontario Hydro which provides for the basic elements of interconnection planning and coordinated operations. This agreement is being revised to broaden coordination between Michigan and Ontario.

Inter-area coordination between ECAR and other areas is governed by the following provision of the ECAR Agreement:

"ARTICLE 6

"INTER-AREA COORDINATION

"6.01 The parties recognize that attainment of their objectives requires continued cooperation between them and other companies outside the East Central Area and particularly cooperation between the parties hereto and companies outside the Area with whose systems they are directly interconnected. Accordingly, the ECA Companies will endeavor to bring about periodic reviews with coordinated areas contiguous to the East Central Area of generation and transmission expansion programs and systems performance to the end of further augmenting reliability of bulk power supply for all. In this connection the parties will attempt to establish liaison arrangements between the Coordination Review Committee and authorized groups in coordinated areas contiguous with the East Central Area."

In order to further implement Article 6 of the ECAR Agreement, the ECAR companies have entered into inter-area reliability coordination agreements with MAAC and CARVA and with NPCC, and an agreement is being prepared with TVA.

A liaison arrangement at present prevails with MAIN. These arrangements will not supersede the necessary system-to-system agreements already in effect which deal with reliability and economic matters, but will provide an additional mechanism to assure adequate review and coordination on a formal basis of plans for the building and operation of major generation and transmission facilities that affect overall bulk power supply reliability between the areas. The existing arrangements between the contiguous systems on the periphery of the East Central Region provide the means to realize economies from the coordinated planning and operation of generation and transmission facilities. It should be pointed out that the absence of formal inter-area reliability coordination agreements has not precluded inter-area investigation of mutual planning and operating problems affecting reliability. Examples in this regard are discussed in Chapter VIII.

Coordination for Economy Within Regional Subdivisions

The preceding sections of this chapter, pertaining to "Bulk Power Supply Reliability for the East Central Region" and "Interregional Coordination," have shown how bulk power supply reliability is being, and will be, achieved within the East Central Region and with other regions with which it is contiguous. This section will describe the arrangements presently existing in the East Central Region whereby economies from coordination are realized.

Within the East Central Region there are regional subdivisions formed by holding company systems, pools, and planning groups, to realize economies within these subdivisions through separate contractual arrangements between and/or among the parties directly concerned. Coordination arrangements, involving generation and/or transmission facilities by two or more electric systems to achieve such economies not attainable by each system separately, include holding company systems, planning and operating pools, planning groups, joint facility ownership arrangements, operating agreements, and contracts for the purchase and sale of capacity and energy.

Exhibit VII.5 identifies the present regional subdivisions within the East Central Region by type and briefly compares the essential functions of each. Appendix VII–B contains detailed statements describing these subdivisions. Exhibit VII.6 shows the size of these subdivisions based on the installed capacity and peak loads as of the end of 1968.

In each regional subdivision the degree of coordination between its electric systems and the benefits presently derived vary with the type and size of the arrangement. The extent that economic ben-

EXHIBIT VII.5

East Central Region—Regional Subdivisions by Type and Function

	AEP	APS	CAPCO	CCD	KIP	Michigan	Michigan-Ontario	MIIO	KII Pool	KU-EK
Holding company	X	X								
Planning and operating pool			X	X	X	X			X	X
Planning group							X	X		
Number member utilities	7	3	5	3	3	2	[1] 3	[1] 6	[1] 3	2
Centralized planning	X	X								
Joint planning			X	X	X	X		X	X	X
Coordinate load projections	X	X	X	X	X	X	X	X	X	X
Coordinate planning for reserves	X	X	X	X	X	X			X	X
Coordinate stability studies	X	X	X	X	X	X	X	X	X	X
Joint ownership generation	X	X	X	X	([2])	X				
Staggered ownership generation	X	X	X		X	X		X		
Central dispatching	X	X				X			1969	
Economic dispatching	X	X	X	X	X	X	X	X		
Exchange capacity and energy	X	X	X	X	X	X	X	X	X	X
Coordinate spinning reserves	X	X	X	X	X	X	X	X	X	X
Coordinate maintenance	X	X	X	X	X	X	X	X	X	X

[1] Includes one system outside East Central Region.
[2] Possible.

EXHIBIT VII.6

East Central Region—Regional Subdivisions-Capacity and Load (1968 Data)

	Net capacity (MW) 12-31-68		Annual peak load (MW)	
Allegheny Power System		3, 606		3, 017
American Electric Power [1]		10, 261		8, 128
CAPCO:				
Ohio Edison-Penn Power [2]	3, 222		2, 793	
Cleveland Electric Ill.[2]	2, 259		2, 287	
Duquesne Light [2]	1, 928		1, 691	
Toledo Edison [1,2]	1, 143		860	
Total APCO		8, 552		7, 631
CCD:				
Columbus and Southern Ohio [3]	1, 141		1, 068	
Dayton Power and Light [2]	1, 014		1, 161	
Cincinnati Gas & Electric [2]	1, 720		1, 678	
Total CCD		3, 875		3, 907
KIP:				
Public Service of Indiana	2, 130		1, 933	
Indianapolis Power & Light	1, 203		1, 122	
Kentucky Utilities	1, 071		937	
Total KIP		4, 404		3, 992
KU-EK:				
Kentucky Utilities	1, 071		937	
East Kentucky RECC [4]	302		271	
Total KU-EK		1, 373		1, 208
Michigan:				
Detroit Edison [1]	5, 388		4, 707	
Consumers Power [1]	3, 662		3, 180	
Total Michigan		9, 050		7, 887
Northern Indiana Public Service [1]		1, 491		1, 263
Kentucky-Illinois-Indiana Pool (KII Pool): [5]				
Big River R.E.C.C., Henderson, Ky	80		93	
So. Ill. Power Coop., Marion, Ill	114		67	
Hoosier Energy Div., Bloomington, Ind	xxx		xxx	
Total KII Pool		194		160

[1] These plus Commonwealth Edison constitute MIIO. Commonwealth not in Region.

[2] See reference to announced plan to study feasibility of forming holding company by these electric utilities.

[3] See reference to announced acquisition by American Electric Power.

[4] Includes 18 distribution cooperative members.

[5] Hoosier has 220 MW of generation being installed

efits from coordination are realized in the East Central Region as a whole is indicated when it is known that the electric systems that constitute these subdivisions own over 90% of the generating capacity in the region.

Of the 401 electric systems in the region in 1967, only 27 were not interconnected with other systems and could not realize potential economic and customer reliability benefits. In 1967 these 27 systems had 473 MW out of 37,619 MW of the installed generating capacity in the region, or 1.2%. Thus, 98.8% of the generating capacity in the region was used to attain economic benefits and improved customer reliability.

Those electric systems under one ownership may most readily realize the maximum benefits attain-

able for economy and service reliability. Depending upon the extent to which individual systems coordinate their planning, construction, and operation through various pooling arrangements, they also may realize reliability and benefits inherent in the economies of scale associated with large power generation and transmission facilities. Other coordinated arrangements may realize lesser benefits depending upon their objectives, types of management, and methods of planning and operation. Those systems which participate in pooling and facilities-planning groups may, because of the need for functioning through contractual arrangements, have a difficult task of equitably distributing obligations, benefits, and costs among the participants to insure that customers and owners of some systems do not subsidize those of others.

The present groups and subdivisions in the East Central Region constitute manageable aggregates for economic coordination, taking into account the number of participating electric systems, their relative sizes, their generation and transmission facilities and the locations of their service areas. However, as technology develops new opportunities, utility managements should review existing coordination arrangements to determine if they are satisfactory. For example, the participants in the CAPCO group and two systems in the CCD group are evaluating the additional benefits, over and above those of their present pooling arrangements, that may be derived through creation of a holding company system.

The possibilities available to a particular electric system for realizing further benefits from economic coordination depend chiefly upon its present situation as to size, location, generation and transmission facilities, ownership, and existing coordination arrangements. One or more of the following possibilities still are available to most electric systems in the region:

1. Participate in mergers, acquisitions, or holding company systems;
2. Join a regional subdivision group;
3. Become an indirect member of a regional subdivision group through agreement with a member and concurrence of other members;
4. Negotiate agreements with a contiguous member of a regional subdivision group to do one or more of the following:
    a. Purchase power for resale;
    b. Dispatch generation jointly;
    c. Coordinate maintenance;
    d. Provide adequate reserves, installed and operating;
    e. Join in ownership of generation or transmission facilities;
    f. Plan installation of facilities jointly.

The Ohio Valley Electric Corporation (OVEC), Appendix VII–C, is an example of a slightly different type of coordination arrangement in which 15 companies, in 1952, joined in large-scale construction of generation and transmission facilities to serve one customer, the gaseous diffusion plant of the Atomic Energy Commission north of Portsmouth, Ohio.

Yankee-Dixie Power, Incorporated, a power systems development corporation, was organized in 1965. It is a federation of municipal electric systems, rural electric cooperatives, and investor-owned utilities operating in 22 eastern and central states. Its purpose is to bring the economic and service benefits of scale and technology to each system to a degree attainable only through joint action.

The objectives of Yankee-Dixie are being pursued through engineering, legal, and finance studies leading to several large, mine-mouth thermal, hydro, and nuclear-powered generating stations, interconnected by EHV lines which will also deliver wholesale power to regional load centers for distribution to retail systems. Financing is proposed through revenue bonds supported by long-term power contracts for the sale of power and use of facilities.

The final plan is expected to offer both economic and reliability benefits to all systems in the proposed area to such an extent that those systems not now represented in Yankee-Dixie will in fact participate and benefit. The Central Section of Yankee-Dixie, consisting of Illinois, Indiana, Kentucky, North Carolina, and Virginia, is anticipating operation status in 1974, with other areas to follow.

The affairs of the corporation are conducted through a 30-member board of directors representing the systems in the 22 states. An office for administrative, planning and coordinating services is maintained in Winchester, Kentucky.

Appendix VII–D lists the membership in Yankee-Dixie Power, Inc., of systems within the East Central Region.

Coordination Between Regional Subdivisions

Coordination among the regional subdivisions, involving both reliability and economy, has been in effect in this region for many years. The systems forming these subdivisions develop plans for generation and major transmission to meet their individual need and those of the subdivision and to obtain economies of scale. Since the establishment of ECAR, these plans are then submitted to ECAR where they are assessed against established criteria for reliability.

Contractual relationships involving two or more separate regional subdivisions are between adjacent systems on a system-to-system or company-to-company basis. These contracts cover the purchase and sale of energy and capacity and the facilities arrangements required to permit such economic transactions at adequate levels of reliability.

Conclusion

The latter portions of this chapter have described how bulk power supply reliability in the East Central Region is being maintained and further augmented on a regional and interregional basis and how economies and service reliability are and can be realized within subdivisions of the region and between contiguous electric systems which may or may not be members of pools or groups. This concept is sound and is working throughout this region. It embodies good organizational principles and keeps the responsibility for management decisions with those legally charged with the operation of each electric system. Under this concept all electric utilities in the East Central Region whose operations affect reliability of bulk power supply, regardless of ownership, can be interconnected to achieve economies and improve service reliability.

CHAPTER VIII

RELIABILITY

The paramount importance of reliability of electric bulk power supply has long been recognized in the East Central Region. This is evidenced by three basic characteristics of the region's major power supply facilities as they have evolved through the past decades and as they exist today, namely, (1) the extent of high-voltage and extra-high voltage transmission, (2) the number and capacity of interconnections among separate utilities within the region and between this region and contiguous areas, and (3) the geographical distribution of its generating plants. While the East Central Region is fortunate to some extent in terms of its geographical location which permits the development of interconnections to the east, west and south, and while the region is favored by fairly widely distributed coal resources to supply its generating plants, it is the extensive development of its transmission facilities to integrate loads and resources that, along with adequate installed generating capacity, assures its high degree of built-in reliability.

Basis for Reliability

Electric bulk power system reliability must have as its basis the adequate planning of facilities, their proper maintenance, and their prudent operation. This requires the extensive study and analysis of alternative programs of system additions before construction, including the simulated testing of their expected performance under all possible conditions. It also requires the establishment of procedures and programs to assure adequate maintenance of power supply facilities and the setting up of proper guidelines for system operation. The remainder of this chapter summarizes how these objectives have been met in the past and are now being met by a group of systems under the East Central Area Reliability (ECAR) Agreement.

Power System Simulation Studies

Simulation studies to duplicate the real-time steady-state and dynamic performance of power systems through the use of mathematical models have for some years provided the basis for planning reliable power systems and for furnishing the guidelines for their safe operation. In the East Central Region these studies may be grouped into four broad categories: (1) internal system studies by individual utilities or power pools, (2) interconnection studies among two or more utilities, (3) multi-system studies covering extensive areas, and (4) regional studies carried out by ECAR.

The East Central Region has a long history of studies, particularly of the first three types. The many interconnections in this region are essentially the product of such studies. Multi-system studies also have been frequently carried out in past years. Probably the earliest studies of this type (1950 onward) were those necessitated by the planning and subsequent operation of the power supply facilities of the Ohio Valley Electric Corporation (OVEC), comprising two major power plants (2,354 MW) and 775 circuit-miles of 345–kV transmission line, to supply the Atomic Energy Commission's diffusion plant near Portsmouth, Ohio. Since the OVEC project involved 15 operating entities (10 power systems), extensive coordinated studies of the combined systems, extending over much of the region, were required.

Other examples of multi-system studies include those conducted by the Michigan-Indiana-Illinois-Ohio (MIIO) group of six interconnected utility systems. These studies led to the creation of the Michigan 345–kV ties with Indiana and Ohio which were placed in operation in 1969. A permanent committee, called for under the MIIO agreement, provides a continuing mechanism for planning and assessing future facilities of common concern to these systems. Extensive operating studies of anticipated performance of the combined sys-

tems affected by the closing of a major transmission loop around Lake Ontario and involving the MIIO systems, Ontario Hydro, and pertinent New York State, Pennsylvania, and other Ohio utilities, also have been carried out.

Studies similar to the above are continually underway among contiguous utilities along the boundaries of the East Central, Northeast and Southeast regions. These analyses are conducted under the auspices of a permanent committee representing the participating utilities. This effort involves both the projection of future transmission facilities and the development of guidelines for their operation.

Extensive studies, either on a continuous or regular periodic basis, have been conducted for many years between utilities in the East Central Region and their counterparts in the Carolinas-Virginias and Illinois-Missouri areas as well as with the TVA system. The many high-capacity interconnections already in operation or scheduled for the immediate future are the product of these studies.

The great volume and extent of power system analyses and simulation studies, referred to above, demonstrate the degree of coordinated planning which has been carried out in the East Central Region, not only to assure optimum system design, but also to provide a reliable transmission network and the guidelines for its operation.

East Central Area Reliability (ECAR) Agreement

ECAR was established in early 1967 in recognition of the need to further augment bulk power system reliability through an organization totally committed to this purpose. It was recognized that a higher degree of coordination on a more formalized basis was necessary because of several factors such as, the rapid growth in scale and complexity of power systems; the accelerated adoption of EHV transmission at 345 kV, 500 kV and now 765 kV with its substantial effect in reducting "electrical distance" between once remote portions of an interconnected network; and the growing interdependence among power systems and their interaction upon each other as a consequence of increased interconnection.

The ECAR Agreement has as its stated purpose ". . . further to augment reliability of the parties' bulk power supply through coordination of the parties' planning and operation of their generation and transmission facilities." The agreement calls for the establishment of "principles and procedures with respect to matters affecting the reliability of bulk power supply, including but not limited to, minimum installed capacity and spinning reserves to be provided by each party by ownership or contract, the distribution of spinning reserves, coordination of generation and transmission maintenance, emergency measures, communications, protection, and the evaluation and simulated testing of systems' performance." It also recognizes the importance of interregional coordination by calling for "periodic reviews with coordinated areas contiguous to the East Central Area of generation and transmission expansion programs and system performance to the end of further augmenting reliability of bulk power supply for all."

ECAR comprises 26 operating utilities (19 systems) which collectively furnish approximately 95% of the power requirements in the East Central Region.

The ECAR organization comprises an Executive Board of one representative from each of 19 systems, a Coordination Review Committee (engineering and operation) with similar representation, seven advisory panels of seven experts, chosen for expertise in their respective areas, and a permanent staff consisting at present of an Executive Manager, two engineers, two engineering assistants, and three secretarial and clerical personnel. Appendix VIII–A shows the ECAR organization.

Since its inception, ECAR has adopted criteria and procedures in the following areas, all of which are fundamentally essential to reliability:

(1) For evaluation and simulated testing of ECAR bulk power supply systems—ECAR Document No. 1—Appendix VIII–B.

(2) For daily operating reserve—ECAR Document No. 2—Appendix VIII–C.

(3) For emergency procedures during declining system frequency—ECAR Document No. 3—Appendix VIII–D.

(4) For uniform rating of generating equipment—ECAR Document No. 4—Appendix VIII–E.

Criteria and procedures in other areas relating to reliability such as required installed reserves, are under preparation.

In addition, ECAR has installed a high-speed teletype network connecting all system control centers and the ECAR Executive Office to permit the rapid communication on a daily basis of system data

and important operating information such as system load and generation in operation and under maintenance, major generation or transmission line outages, and other essential data. Reporting procedures have been set up regarding the status of generation and transmission under construction. Compilations of anticipated load, installed generation, maintenance schedules, capacity reserves, and interchange transactions are maintained on a periodically updated basis up to 2 years in advance. Reports on anticipated generation and transmission conditions and critical transmission facility lists are issued semiannually, based on extensive simulation study and analysis. Future system plans are compiled and reviewed for adequacy.

Reliability—Its Future Implementation

The continued achievement of bulk power supply reliability in the East Central Region rests, first, on each major power system providing the necessary physical facilities and, second, on the assurance that the addition of such facilities will contribute to and not detract from the overall reliability of the interconnected network. Regional coordination, as exemplified in ECAR, provides the mechanism for the continued achievement of these objectives. ECAR's participation in the activities of the National Electric Reliability Council (NERC) assures effective coordination of its efforts with those of other similar regions.

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CHAPTER IX

ENVIRONMENTAL CONSIDERATIONS

In recent years, an increasingly deep concern regarding the environment and aesthetics of our cities, suburbs, and rural areas has been building up among responsible citizens in government, business, educational institutions, and within the public at large. This concern is well founded, since our society—while enjoying the many fruits of a growing economy—cannot allow through lack of foresight and advance planning the uncontrolled encroachment of a technological civilization on its natural environment. This is particularly true in those instances where the changes introduced by the growing needs of an industrial economy could endanger in an irreversible manner the inherent balancing processes of nature.

The electric power industry shares with society at large its concern for the protection and preservation of our environment. It has a great stake in the social and physical well-being of its communities. It is dedicating itself with increasing determination to improving the appearance of power supply facilities and to reducing, to the fullest extent practicable, any adverse impact which they might have on the environment. At the same time, the electric power industry is fully aware of the extent to which the vitality and the well-being of the nation depends on the ample supply of reliable, low-cost electric power.

In considering the preservation of our environment, the challenge for the years ahead lies—in the face of a growing population demanding ever higher standards of living—in finding the proper balance between the social objectives of improved aesthetics and environment on the one hand and further advances in our economic well-being on the other hand. It must be recognized that these two objectives in many instances are in conflict. We cannot maintain or continue to develop an ever higher standard of economic affluence without accepting some of the tangible and sometimes not too attractive physical evidences of a highly industrialized economy, such as highways, automobiles, airports, steel mills, refineries, chemical plants, as well as transmission lines and generating plants. In the area of electric power supply, the challenge for the governmental and regulatory agencies, the electric power industry, and the public at large lies, therefore, in searching for and finding a reasonable balance between two valid concerns—the one, low-cost electric energy to be supplied, and the other, the environment to be protected.

Introduction

The environmental problems of electric power supply have many ramifications. They can be classified into three broad areas, namely:

1. Air pollution, due to particulate and gaseous emissions from power plants into the the atmosphere;
2. Water pollution, a term which, when related to power plants, is used to describe the problem of heat released into natural bodies of water or into streams, and
3. Aesthetic considerations, which involve the appearance of power plants, transmission lines, and substations.

Unfortunately, these problems are not entirely separate from each other and the solutions, required to conform to regulations issued for their separate correction, are sometimes mutually exclusive. Thus, steps to minimize gaseous pollution may well increase the particulate emission in a specific case. Likewise, the use of hyperbolic cooling towers to overcome thermal pollution on a small stream may be considered by some to be aesthetically objectionable.

Environmental problems involve more than the environment. They involve people, and the priorities that people assign to different changes in that environment. In the field of biology and health, changes may occur slowly or swiftly, and the results of the changes may be reversible or not. Particularly in matters of health, the public rightly desires to

avoid irreversible changes of a harmful nature. This normal and proper desire to prevent irreversible changes unfortunately has produced, in some instances, public pressure for limits that are far lower than can be justified by any present knowledge of the health effects due to long-term low-level exposure.

Air Pollution

Particulates

The problem of the emission of particulate matter from power plants is an old one. For at least 45 years both mechanical collectors and electrostatic precipitators have been used to minimize such emissions when coal is burned as pulverized fuel. Originally mechanical collectors were used alone or in combination with electrostatic precipitators, but in the past ten years there has been a trend to rely entirely on large electrostatic precipitators. In early applications the collection of particulate matter was not highly efficient, even though the inherent technological capability was available. As shown in a paper by W. W. Moore at the Third National Conference on Air Pollution, Washington, D.C., December 1966, the situation has now changed to the extent that the utility industry has almost completely closed the gap between the technological capability of precipitators and the guaranteed efficiency of newly installed dust-collecting equipment. The dramatic way in which current practice has caught up with technology can be seen in Exhibit IX.1. Virtually all collectors are now being purchased with efficiencies in the 97% to 99% plus range. By employing generous design and allowing for some inadequacy in the knowledge of the resistivity of many fly ashes, there is at hand an adequate technology to cope with the emission of particulates. Some present research suggests that particulates may be the triggering mechanism in creating problems from the gaseous emissions; it is therefore fortunate that precipitator technology is able to deal effectively with the particulates.

Regulations dealing with the emission of particulate matter have greatly increased in severity during the past twenty years. This can readily be seen from Exhibit IX.2. New plants can be, and are, designed to meet such regulations as are in force at the time they go into service. When new regulations are promulgated they frequently allow for emission of about 25% more material from existing plants than from new units. However, in view of the very strict

EXHIBIT IX.1

GROWTH IN EFFICIENCY LEVEL OF FLY ASH COLLECTORS CAPABILITY VERSUS ACTUAL USE

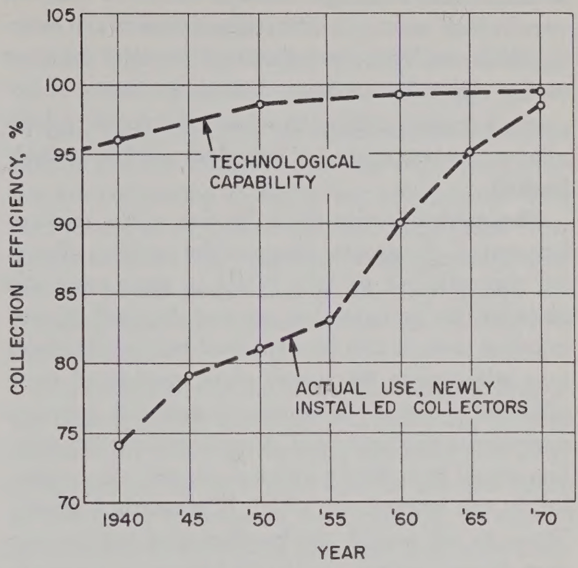
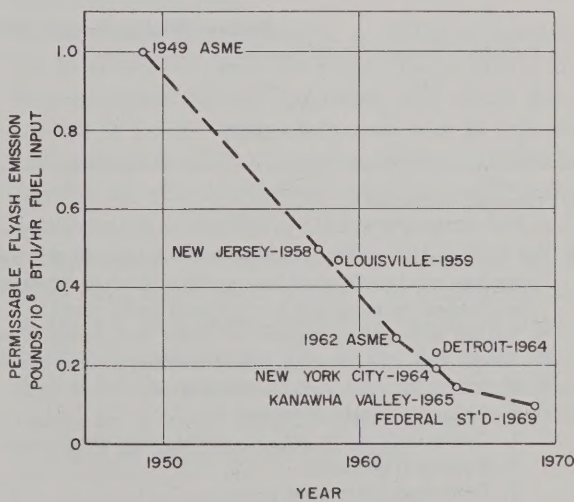


EXHIBIT IX.2

TREND OF EMISSION LIMITS FOR LARGE UNITS



limits being applied to new units, a 25% allowance for existing plants quite often results in requiring the total replacement of their dust-collecting equipment.

As an example, a unit built prior to 1949, and emitting slightly more than one pound of ash per million Btu input, must be modified to meet a code where a new plant is restricted to 0.19 pounds per million Btu input, and the existing units are allowed

0.25 pounds. The required electrostatic collector, to reach the 0.25 figure allowed for old plants, will be so large that structural changes required will not permit their erection within the confines of the existing structure. Since precipitators are very sensitive to the approach configuration of the ducts, it becomes a major problem to achieve the required high efficiency when space for new duct work is severely limited.

The more effective the collection of the particulate matter, the greater becomes the problem of storing the collected fly ash. While in some cases this material can be barged to sea and disposed of, and in other cases it can be deposited behind diked-off area adjacent to the power plant, neither of these solutions is entirely adequate or desirable from an environmental standpoint. A really satisfactory solution would be to find a major economic use, or uses, for fly ash beyond any which is presently foreseen. Thus, fly ash would not be discarded but become part of some material or device having an economic value of its own. In view of the years spent in trying to develop bulk markets for fly ash, and the limited success in doing so, this goal may seem beyond reach. However, the formation of the National Ash Association within the last two years shows that the utility industry has not abandoned hope for creating a sizeable market for this waste product. The magnitude of this problem can be seen from the national figures on ash production and ash use for the year 1968, as given in Exhibits IX.3 and IX.4.

EXHIBIT IX.3

Ash Collected and Utilized by Utilities in the U.S.A. for Year 1968

	(Tons)
Fly ash	19, 813, 747
Bottom ash	7, 259, 212
Boiler slag	2, 554, 569
Total ash produced	29, 627, 528
Total ash utilized	5, 194, 016
Percent fly ash utilized	9. 6
Percent bottom ash utilized	25. 0
Percent boiler slag utilized	57. 8
Percent total ash utilized	17. 5

EXHIBIT IX.4

Major Methods of Utilizing Ash for Year 1968

	Fly ash (tons)	Bottom ash (tons)	Boiler slag (if separated from bottom ash) (tons)
1. Total ash collected	19, 813, 747	7, 259, 212	2, 554, 569
2. Ash utilized (ash utilized includes ash sold as well as used by company for its own use in concrete, road base stabilization, etc. Does not include ash hauled or pumped by company to a disposal or fill area):			
A. Mixed with cement clinker or mixed with cement (pozzolan cement)	23, 458		
B. Mixed with raw material before forming cement clinker	107, 666	17, 510	23, 025
C. Stabilizer for road bases, parking areas, etc	141, 142	17, 009	69, 046
D. Partial replacement of cement in:			
1. Concrete products (blocks, bricks, pipe, etc.)	113, 790		17
2. Structural concrete	106, 244		
3. Dams and other mass concrete	92, 411		
E. Lightweight aggregate	190, 192	32, 387	
F. Fill material for roads, construction sites, etc	205, 757	583, 094	964, 220
G. Filler in asphalt mix	103, 827	13, 820	63, 604
H. Miscellaneous	132, 258	448, 445	256, 136
Total item No. 2	1, 216, 745	1, 112, 265	1, 376, 048
3. Ash removed from plant sites at no cost to utility but not covered in categories listed under "Ash Utilization"	686, 738	705, 788	96, 432
Total utilized items No. 2 and No. 3	1, 903, 483	1, 818, 053	1, 472, 480

Inclusion of fly ash in concrete, and of boiler slag in road surfacing mixtures, has proven highly beneficial. In some areas, however, outmoded regulations prohibit the use of such materials in state highways. Rescinding these regulations would provide further useful ways in which to dispose of considerable tonnages of these materials.

Gaseous Emissions

At the present time two gaseous emissions from power plants are under serious study—sulfur dioxide (SO_2) and the nitrogen oxides. Because of sulfur dioxide's connection with copper smelters and the undoubted damage done to forest trees by smelter fumes, it has been studied for a much longer time. Even so, its health effects and true role in air pollution are not well established. A great deal of further work needs to be done to prove that some of the very low SO_2 limits now being legislated are necessary. In this regard, the Dutch Report G–300, "Sulfur Dioxide—To What Level Is It Acceptable?" prepared by Brasser, Joosting and van Suilen, should be referred to, since its conclusions are considerably at variance with those published in 1967 by the U.S. Department of Health, Education, and Welfare.

In order to clarify the health effects of gaseous emissions from power plants, the Edison Electric Institute in 1966 commissioned Hazleton Laboratories, Inc., to make a thorough test of the physiological effects of sulfur oxides and fly ash, both singly and in combination. This is a fairly long-term experiment using concentrations of fly ash and sulfur oxides such as might be found under rather bad metropolitan conditions. The work will extend over a period of at least 5 or 6 years, and is expected to provide very useful data. The budgeted cost of this project is $2.2 million.

In addition to this research project Edison Electric Institute has had one or more other projects related to air pollution underway since 1958. These include:

a) 1958–1966—A project for sulfur removal from coal.

b) 1958–1964—Early work on catalytic oxidation of SO_2 in stack gases, to recover sulfuric acid.

c) 1960–1966—A study of stack plume opacity, co-sponsored by the U.S. Public Health Service.

d) 1963–1966—A project on utilization of fly ash.

e) 1966–1970—Second project to remove sulfur from coal.

f) 1966–1970—Project on the fate of SO_2 in stack plumes, co-sponsored with others.

Aside from the clean air research done under the Edison Electric Institute's sponsorship, many utilities are committed to significant programs of their own aimed at SO_2 removal from stack gases. Also, many utilities now monitor SO_2 concentrations around power plants and much helpful data for checking diffusion equations can be obtained in this fashion.

Since much of the coal in the East Central Region has relatively high sulfur content and many existing boilers were designed to take advantage of other properties of the local fuel, such as low ash fusion temperature, it becomes very difficult to convert such plants to low sulfur fuel even if it were available at a reasonable price. A study by the Battelle Memorial Institute of Columbus, Ohio, has investigated the cost effect of trying to convert all boilers in the State of Ohio to burn the fuel recommended at the Vienna, West Virginia, Abatement Hearing in 1967. This study will be released shortly and should be meaningful.

Since there are, at present, no effective methods for SO_2 removal, and low sulfur coal in many instances is prohibitively expensive, tall stacks have proved to be the most satisfactory way to achieve low ground-level SO_2 concentrations. Tall stacks provide an effective interim solution, pending the development of satisfactory SO_2 removal techniques.

One means of improving the disposal of stack gases from large power plants is to concentrate all of the gas in a single stack. This provides a substantial increase in the rise of the hot gases after they leave the stack and, for a given stack height, results in a lower ground level concentration of SO_2 and of all other effluent gases.

Water Pollution

Neither fossil nor nuclear power plants need to create water pollution in terms of discharging sewage or industrial waste into streams or lakes. All steam-electric plants, however, must discharge waste heat into the environment. This waste heat, given up by steam in the power plant condensers, is first absorbed by the flow of cooling water and then discharged into the lake, stream, or river located in

the proximity of the plant. This discharge of waste heat results in an increase in the temperature of water receiving the discharge. Eventually, all waste heat is dissipated into the atmosphere.

Available knowledge is not sufficient to establish with any degree of certainty the effect of increased water temperature on the aquatic life of a lake or stream. While one of the effects of higher water temperature is an increase in the rate of biochemical processes on the one hand and a reduction in the amount of oxygen dissolved in the water on the other hand, the overall impact of higher water temperature depends in each instance on a variety of additional factors, including climatic conditions, the type of existing aquatic life, the extent of chemical and organic pollution already present, and many others. Depending on circumstances, the effect of increased water temperature may be beneficial or detrimental. Thus, adverse public reaction to the thermal effects of nuclear and fossil-fuel power plants is oftentimes based on misinformation. Extensive additional research is needed in this area, so as to avoid the imposition of unduly stringent, restrictive, and costly regulations in this regard.

While additional research is needed to determine the effect of higher water temperatures on aquatic life for a wide range of conditions, it appears certain that in many instances the extent of waste heat discharge from thermal power plants into lakes and streams will need to be limited in the years ahead. This is particularly so when one considers the increasingly large number of power plants that, over the years, will need to draw upon the same limited amount of naturally available cooling water.

It is reasonable to assume, therefore, that some form of cooling tower, either the induced draft type or the natural draft hyperbolic type, will need to be used on most future power plants built on the rivers and streams in the East Central Region. The capital cost of hyperbolic towers is very close to $5/kW, with the induced draft type somewhat lower. Evaluation of load factor, power costs, terrain conditions contiguous to the plant and meteorological factors must be carefully made to choose the proper tower for any specific site.

Considerable speculation continues concerning dry-type cooling towers, including the Heller System, direct condensation in finned tubes, and a two-fluid cycle consisting of steam and some refrigerant gas such as F–12 or F–21 for the last few stages. This might avoid freezing problems with the direct condensing surface, which would otherwise be a constant winter hazard. Some work is being done on components for dry towers, but no refined estimate of costs per kW for a dry tower is available.

Aesthetics

Power plants vary widely in the aesthetic impression they make on the viewer. Sound architectural treatment to insure some blending and balance between areas, colors and texture of the various surfaces can contribute greatly to their appearance. As electrostatic precipitators have increased in efficiency, the appearance of the stack plume has improved and at present, in modern plants, is barely detectable when they are at full load. Unfortunately, this is often not the case during start-up periods, and precipitator manufacturers are being pressed to find means to operate the dust-collecting equipment during these periods.

There has been some objection to the appearance of hyperbolic cooling towers both in this country and in England. These objections might be overcome to some extent if the public understood that this is a device used to improve the environment. While in England there have been efforts to camouflage hyperbolic cooling towers, in this country those towers erected thus far have been left without embellishment of any kind. American practice accentuates the clean lines and functional nature of the device, which is probably the best way to handle the appearance problem.

It has been suggested in the past that high-voltage transmission lines should be placed underground to improve the aesthetic appearance of the environment. The technological and economic impossibility of underground high-voltage transmission has been clearly pointed out by several recent reports, including those of Citizens Advisory Committee, the Electric Utility Industry Task Force on Environment, and the Working Committee on Utilities of the President's Council on Recreation and Natural Beauty. High-voltage transmission lines, therefore, will need to remain a part of our environmental scene just as highways, railways and other essential elements of our technological civilization. Transmission lines, in some instances, can be routed to take advantage of topographical features and thereby be less visible. Good practice during and following the construction period will preserve essential ground cover. Use of higher transmission voltages, now available to the industry, will reduce the number of lines radiating from a

major power center, thereby contributing to an improved aesthetic effect. New designs of both transmission towers and distribution poles have been proposed in recent years and are finding application in the East Central Region.

The appearance of substations can be improved through judicious site selection, low profile, carefully selected color schemes for equipment structures and control houses, landscaping, and—for lower-voltage stations—some fence line screening.

CHAPTER X

PATTERNS OF GENERATION AND TRANSMISSION

Prior chapters in this report have examined the basic parameters that go into the formulation of a program of generation and transmission to meet projected load levels in the East Central Region. These load levels have been estimated at approximately 45,000 MW,[1] 83,000 MW,[1] 150,000 MW,[1] in the years 1970, 1980, and 1990, respectively.

Bulk power supply facilities to meet the 1970 load requirements have already been committed and are now nearing completion. Similarly, generation and transmission plans for the first half of the decade 1971–1980 are either committed or in an advanced stage of planning. On this basis, the overall power systems' configuration for 1980, as described herein, may be considered as fairly indicative of the pattern of expansion which will be followed by the utilities in the region during the next decade. It is the period 1981–1990 which must be considered more speculative. This is particularly true in an industry such as that of electric power supply which is characterized by rapid technological change and development. It is with full recognition of the uncertainties of the future, both in terms of the amount and geographical distribution of electric power requirements and in terms of the facilities best able to meet those requirements, that the 1981–1990 program outlined below is given as one possible pattern for generation and transmission expansion. Undoubtedly, other alternative programs will require future consideration.

The 1970 System

Generation

By 1970, the installed generating capacity within the East Central Region will total slightly in excess of 55,000 MW. Of this total, approximately 92% will be fossil-fired, 2% will be nuclear, and the remaining 6% will constitute other forms of generation, such as pumped storage, hydro and various types of fossil-fired peaking capacity. As previously pointed out, the vast bulk of the fossil-fired generation will draw upon the region's extensive coal resources. The nuclear generation in service will include: Palisades—770 MW; Shippingport—100 MW; Big Rock—70 MW; and Fermi—61 MW.

The distribution by unit size of thermal generation in service by 1970 is shown in Exhibit X.1. As seen from this exhibit, about 70% of the total thermal generation installed in the region will be in units of 300-MW size and smaller, with units in the 0–100-MW and 101–200-MW categories each accounting for about 25% of the total. Of those units with ratings greater than 300 MW, sizes in the 501–600-MW and 601–700-MW categories will account for about 15% of the total thermal capacity in the region. This exhibit reflects the growing trend during the past several years toward larger unit sizes in order to take advantage of inherent economies of scale. Approximately 90% of all new thermal capacity installed during the 1966–1970 period are in sizes greater than 400 MW, with units in the 501–600-MW category accounting for about one-third of all new installations. The map included at the back of this report, depicting the combined 1970 systems in the East Central Region, gives the location of all generation, existing and planned for service by 1970. In addition, Exhibit X.2 shows location by FPC Power Supply Areas (PSA's), together with a breakdown by size and type of unit.

Transmission

In 1970, the major bulk transmission systems in the region will be at 230 kV, 345 kV and 500 kV, with several major lines at 765 kV already in operation. The 230-kV transmission is centered exclusively in Indiana. The EHV network, comprising 345-kV and higher voltages and amounting to approximately 6,000 circuit-miles of transmission line,

[1] These load levels were developed by the Task Force on Patterns of Generation and Transmission and average about 3% greater than those given in Chapter II.

EXHIBIT X.1

EAST CENTRAL REGION

PERCENT DISTRIBUTION OF STEAM GENERATING CAPACITY BY UNIT CLASS IN SERVICE AT END OF YEAR

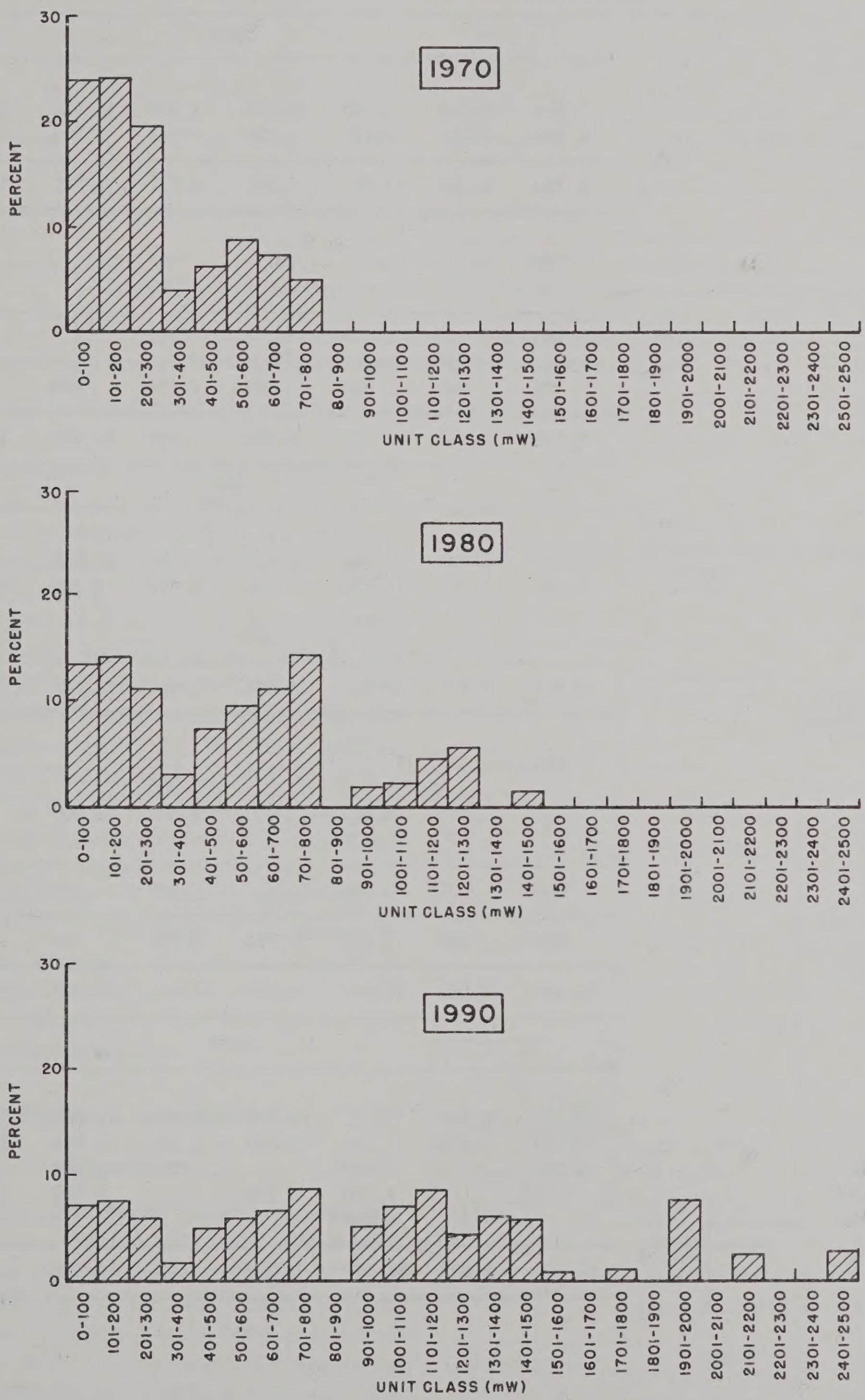


EXHIBIT X.2

FPC-East Central Region—Patterns of Generation and Transmission Generating Capacity in Megawatts

Source of capacity (MW)	PSA 7	PSA 8	PSA 9	PSA 10	PSA 11	PSA 12	PSA 19	Total region
				1970				
Fossil units:								
0–400	3,654	2,043	8,385	2,675	7,908	10,938	1,570	37,533
401–800	2,766	625	3,271	1,250	1,813	3,404		13,129
Total	6,420	3,028	11,656	3,925	9,721	14,342	1,570	50,662
Nuclear units:								
0–400	100				233			333
401–800					700			700
Total	100				933			1,033
Other units	72	380	303	663	1,174	890	38	3,520
Total capacity	6,592	3,408	11,959	4,588	11,828	15,232	1,608	55,215
				1980				
Fossil units:								
0–400	3,654	2,403	8,385	2,675	7,908	11,818	1,945	38,788
401–800	6,006	1,250	11,236	2,850	3,383	9,409	2,125	36,259
801–1,200								
Over 1,200				1,300			3,900	5,200
Total	9,660	3,653	19,621	6,825	11,291	21,227	7,970	80,247
Nuclear units:								
0–400	100				233			333
401–800					2,800			2,800
801–1,200			3,600		4,460	2,200		10,260
Over 1,200			1,500					1,500
Total	100		5,100		7,493	2,200		14,893
Other units	822	380	1,233	2,633	2,424	890	38	8,420
Total capacity	10,582	4,033	25,954	9,458	21,208	24,317	8,008	103,560
				1990				
Fossil units:								
0–400	3,654	2,403	8,385	2,675	7,908	12,068	3,175	40,268
401–800	6,006	1,250	11,236	2,850	3,383	13,784	2,125	40,634
801–1,200	3,000		7,000			6,300	1,120	17,420
1,201–1,600			1,500	1,300		3,100	3,900	9,800
1,601–2,000			8,000					8,000
Total	12,660	3,653	36,121	6,825	11,291	35,252	10,320	116,122

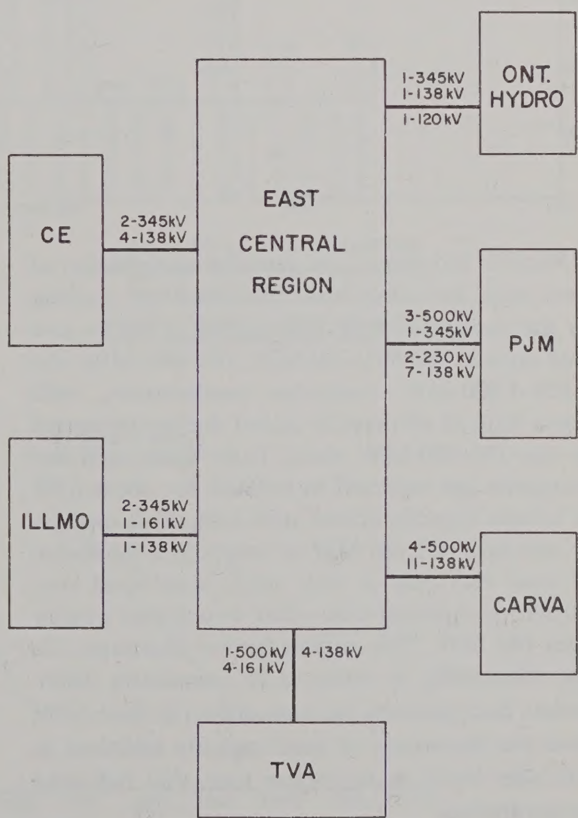
FPC-East Central Region—Patterns of Generation and Transmission Generating Capacity in Megawatts—Continued

Source of capacity (MW)	PSA 7	PSA 8	PSA 9	PSA 10	PSA 11	PSA 12	PSA 19	Total region
				1990—Continued				
Nuclear units:								
0–400	100				233			333
401–800					2, 800			2, 800
801–1,200	3, 700		7, 000		7, 740	2, 200		20, 640
1,201–1,600		3, 000	8, 400		5, 600	4, 100		21, 100
1,601–2,000			6, 000		1, 800			7, 800
2,001–2,400					4, 400			4, 400
Over 2,400				5, 000				5, 000
Total	3, 800	3, 000	21, 400	5, 000	22, 573	6, 300		62, 073
Other units	1, 722	380	1, 233	2, 633	3, 544	890	38	10, 440
Total capacity	18, 182	7, 033	58, 754	14, 458	37, 408	42, 442	10, 358	188, 635

will overlay and reinforce extensive 138-kV and 230-kV systems. The map referred to above shows these combined transmission systems. In addition, 161 kV will continue as a transmission voltage in some areas of Kentucky.

The EHV network in service in 1970 is shown on a separate map included at the back of this report. This 6,000-mile network will consist of 500 circuit-miles at 765 kV, 600 circuit-miles at 500 kV and 4,900 circuit-miles at 345 kV. These facilities will continue to constitute the heaviest concentration of EHV in the United States and, for that matter, in the world. Also, unique in this regard, are the large-capacity transmission ties with other regions, including one 765/500-kV, seven 500-kV and six 35-kV interconnections with contiguous systems in those regions. These ties are in addition to lower voltage interconnections at 230 kV, 161 kV and 138 kV. Exhibit X.3 shows the number and voltage of such interconnections.

EXHIBIT X 3
EAST CENTRAL REGION INTERCONNECTIONS
1970



1971–1980 Patterns of Expansion

Generation

To meet the anticipated power requirements during the ten-year period 1971–1980 will require the installation of approximately 48,000 MW of new generating plant in the East Central Region, reaching a total of about 100,000 MW of installed capacity by the end of that period. Of the capacity to be added, approximately 60% is expected to be

fossil-fired, 32% nuclear, and the remaining 8% pumped storage or other forms of peaking plant.

With the expected mix in types of generation capacity additions between 1971 and 1980, the distribution of total installed capacity by 1980 in the East Central Region will be approximately 76% fossil-fired, 16% nuclear and 8% pumped storage and other types of peaking generation. Coal-fired generating plant is expected still to play the dominant role in supplying the capacity needs of the region; however, its position vis-a-vis nuclear is expected to decline from 92% of all capacity in 1970 to the 76% figure in 1980. This reflects the start of a modest nuclear expansion program in some portions of the region. Exhibit X.4 shows the breakdown of capacity in percentage of total capacity installed.

EXHIBIT X.4
EAST CENTRAL REGION
PERCENT BREAKDOWN BY TYPE
OF GENERATING CAPACITY IN SERVICE
1970-1990

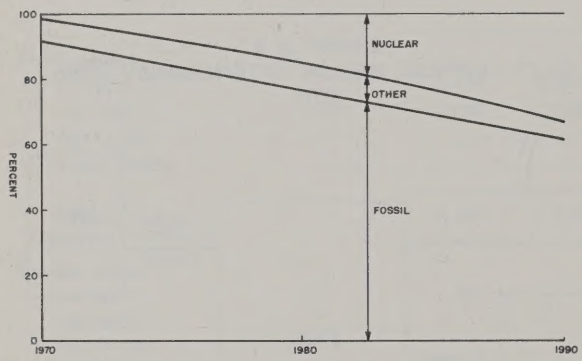


Exhibit X.5 shows the probable distribution of new units, including both fossil-fired and nuclear, by size categories. From this exhibit it can be seen that units in the 601–700-MW, 701–800-MW, and 1,201–1,300-MW categories predominate, with about 25% of all capacity added during this period in the 701–800-MW class. These three unit size categories are expected to account for about 55% of all new capacity added, with 25% of all capacity in unit sizes of 1,100 MW or larger. It is significant to note that only a very small amount of new capacity is expected to be added in unit sizes smaller than 400 MW. This exhibit further illustrates this size relationship in terms of its cumulative distribution. Each point on the curve shown in this exhibit gives the percentage of total capacity additions in unit sizes equal to or greater than that indicated by the abscissa.

Reference to Exhibit X.1 shows a significant change in the overall composition of unit sizes installed by 1980 with those in existence in 1970. Whereas in 1970 about 70% of all units installed in the region were in sizes of 300 MW and smaller, by 1980 such units will amount to less than 40% of the total. This is continued evidence of the drive toward larger unit sizes to achieve economies of scale.

The anticipated locations of generating capacity additions in the East Central Region are shown in the 1971–1980 map included at the back of this report. Exhibit X.2 also gives the location of all installed capacity in 1980 by PSA's together with a breakdown by type and size of unit.

Transmission

During the 1971–1980 period, substantial additions in EHV transmission are contemplated within the East Central Region. These include about 2,100 circuit-miles of 765 kV (1,200 miles of which will be in service by 1972), 600 circuit-miles of 500 kV and 4,800 circuit-miles of 345 kV. The total circuit-miles of installed EHV transmission by voltage class is given in Exhibit X.6. This exhibit shows the relative growth in each voltage class, projected from 1970 to 1990. The aggregate of all EHV transmission (345 kV and above) in the region by 1980 is estimated at about 13,500 circuit-miles which is more than double the 6,000 circuit-miles in existence in 1970. This very substantial expansion in EHV is essential to meet the load requirements of the region, integrate its generating plants and load centers, and interconnect at EHV the various areas within the East Central Region as well as reinforce its interconnections with neighboring regions.

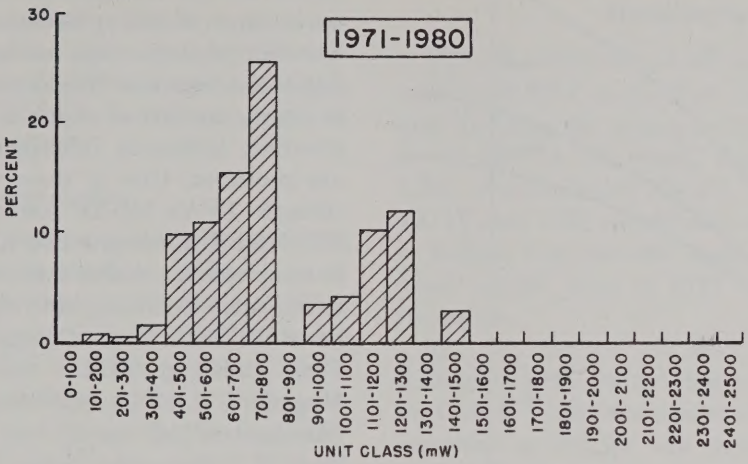
The rapid development of 765 kV as a major bulk power transmission voltage, from its initial use in 1969 to over 2,500 circuit-miles by 1980, reflects a recognition both of the inherent economies of 765 kV to meet the region's growing demands and the very substantial reduction it allows in right-of-way requirements or land use per kilowatt of power transmitted.

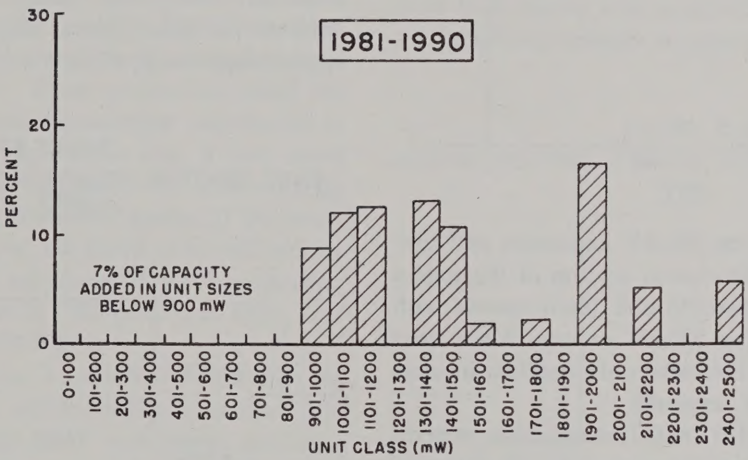
The continued expansion of 345 kV and 500 kV, in addition to the introduction of 765 kV, constitutes a logical pattern for transmission development in the East Central Region. Reference to the 1971–1980 map, included in the back of this report, shows that the growing 765-kV network will constitute an overlay on the 345-kV systems which predominate

EXHIBIT X.5

EAST CENTRAL REGION

PERCENT DISTRIBUTION OF STEAM GENERATING CAPACITY IN A UNIT CLASS ADDED BETWEEN YEARS





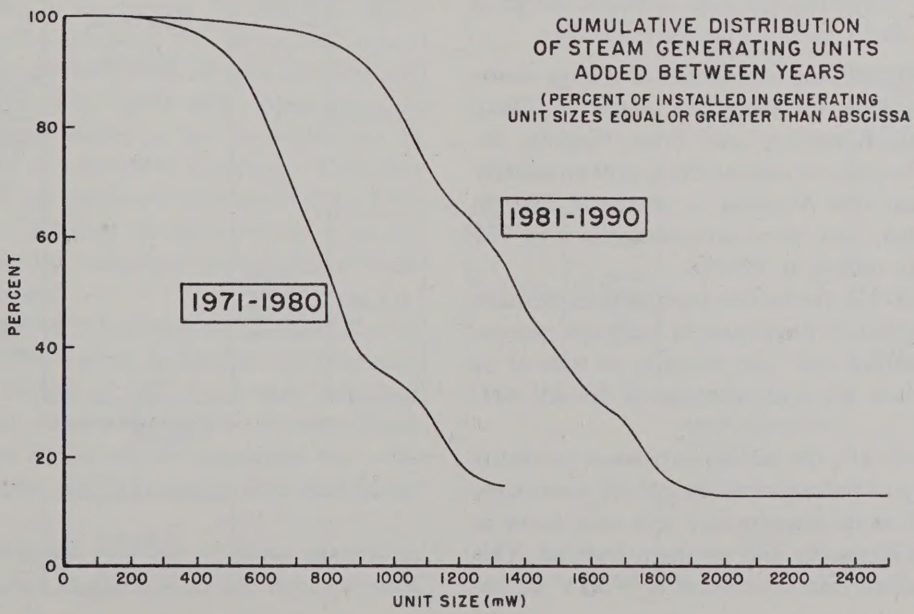
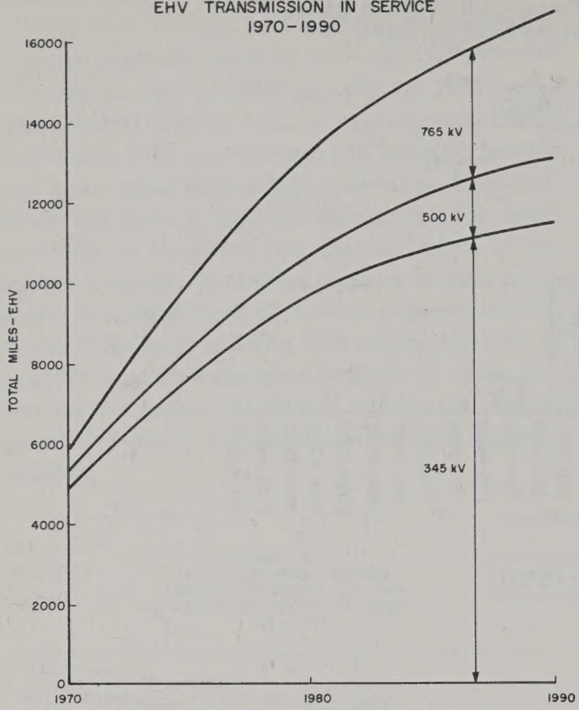


EXHIBIT X.6
EAST CENTRAL REGION
BREAKDOWN BY VOLTAGE CLASS OF
EHV TRANSMISSION IN SERVICE
1970-1990



in the area, while the 500-kV expansion will continue entirely in the eastern portion of the region where it is contiguous to and interconnects with existing and evolving 500-kV systems. These contiguous systems in themselves are overlays in most instances of 230-kV networks.

Specifically, the 1971–1980 transmission pattern, as presently contemplated and shown in the map referred to above, provides for the following:

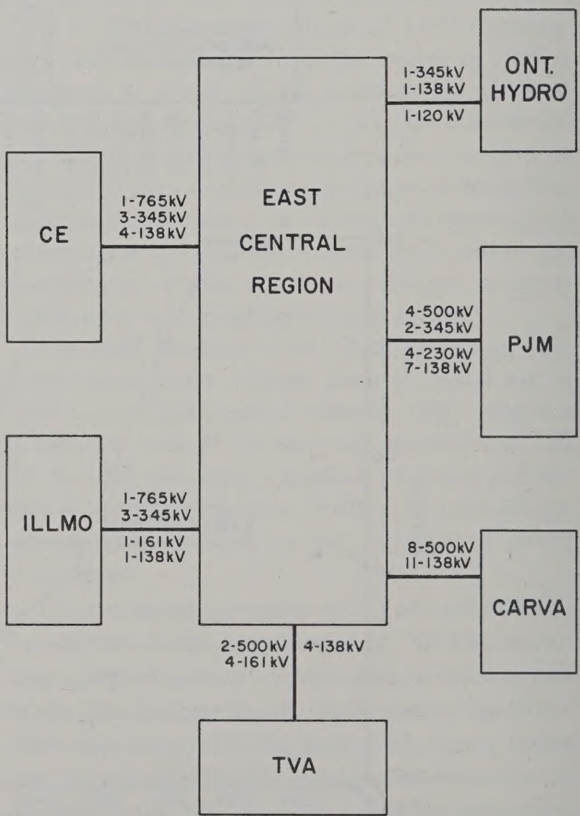
At 765 kV, the completion of a large transmission loop involving the States of Ohio, Indiana, Kentucky, and West Virginia, bisected by a line in central Ohio, with an easterly extension into Virginia, a northerly spur to Michigan, and three interconnections at 765 kV with utilities in Illinois.

At 500 kV, the further expansion in the eastern portion of the region to integrate generation sources and load centers, as well as to strengthen ties with contiguous 500-kV networks.

At 345 kV, the further expansion in almost all parts of the region where 345 kV now exists, as well as its introduction into such areas as central Kentucky and southern Indiana. This will include the creation of a 345-kV tie between Toledo and Cleveland and the use of 345 kV as the principal bulk power supply to most major load centers.

The 1971–1980 period will also see the further development of major interconnections between the East Central Region and contiguous areas. In addition to the three new 765-kV ties to Illinois referred to above, the first of which is already under construction, additional 765/500-kV interconnections are projected. One of these would close a loop through TVA's 500-kV system by establishing a 765/500-kV interconnection in western Kentucky to complement a similar interconnection created in northeastern Tennessee in 1970, and another would tie to the Duke Power Company's 500-kV system. Four additional 500-kV ties to the Carolinas-Virginias (CARVA) and Pennsylvania-New Jersey-Maryland (PJM) systems are also indicated. Exhibit X.7 shows the extent of interconnection between the East Central Region and contiguous systems expected by 1980.

EXHIBIT X.7
EAST CENTRAL REGION INTERCONNECTIONS
1980



1981–1990 Pattern of Expansion

As indicated in the introduction to this chapter, any projection of generation and transmission for the period 1981–1990 can be made only on a broad conceptual basis and in all probability will be significantly altered in the light of future developments. The program described below is one possible alternative which would appear to meet the region's power requirements in 1990.

Generation

By 1990 the total installed generation required to meet anticipated load demands in the East Central Region will be in the order of 190,000 MW. This represents an addition of about 81,000 MW during the 10-year period 1981–1990. The projected breakdown by type of generation added is 43% fossil-fired, 55% nuclear, and 2% in miscellaneous other forms. The resultant distribution of the total installed capacity by 1990 is 60% fossil-fired, 34% nuclear, and 6% in pumped storage and other types of peaking capacity. These projections show the growing role of nuclear generation anticipated in the future and the expectation that it may move ahead of fossil-fired generation in new capacity additions during the 1981–1990 period. If this prognostication proves true, coal-fired units will decline from a position of supplying 76% of generating capacity requirements in 1980 to 60% in 1990. This trend is shown in Exhibit X.4.

Exhibit X.5 shows a possible distribution of thermal generation additions (both nuclear and fossil-fired), by categories of unit size, as estimated by the utilities in the region for the 1981–1990 period. Excepting for about 15% of the total capacity installed during this period, all units are projected in sizes greater than 1,000 MW. Approximately 50% of all units shown in the projection are in the 1,000-MW to 1,500-MW size range. Unit sizes up 2,500 MW are projected with about 6% of the total capacity additions in this category. This exhibit also shows the cumulative distribution of these capacity additions.

The composition of unit sizes for all thermal units in service in 1990 is given in Exhibit X.1. The continuing and substantial shift from early additions in average unit size can be readily observed. These projections are based on the conviction that continued economies can be achieved from still larger unit sizes.

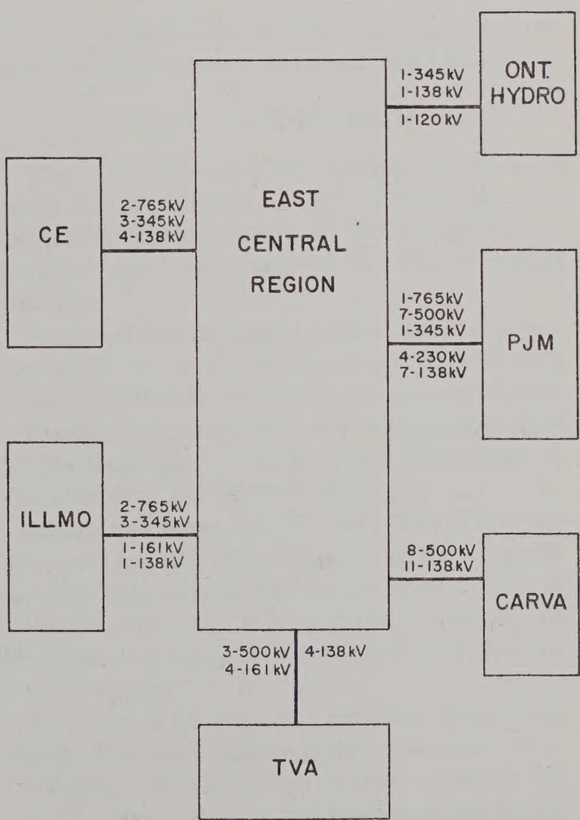
The approximate location of these generation additions is given in the 1981–1990 map included at the back of this report. Also, Exhibit X.2 shows the location of all generation in service by 1990 by PSA's, together with their type and category of unit sizes.

Transmission

The 1981–1990 period will see the continued expansion of EHV in the East Central Region. The map depicting the systems for this period, included at the back of this report, shows the addition of 1,200 circuit-miles of 765 kV, 300 circuit-miles of 500 kV, and 1,800 circuit-miles of 345 kV. As shown in Exhibit X.6, this will result in an aggregate of nearly 17,000 miles of EHV transmission line in the region.

By 1990, 765 kV will have become the major bulk power EHV voltage class in the area, constituting close to 4,000 circuit-miles of line. Transmission expansion at 345 kV will continue both to serve local load centers and to provide, in certain areas, an underlying network to support the 765-kV over-

EXHIBIT X.8
EAST CENTRAL REGION INTERCONNECTIONS
1990



lay. In the eastern portion of the region, 500 kV will continue to provide the major EHV transmission voltage.

Although no voltage higher than 765 kV has been projected in this transmission expansion pattern for the East Central Region, it is quite probable—as pointed out in Chapter V of this report—that a voltage level in the 1,200–1,500-kV class may be initiated in the 1981–1990 period. Research is already underway in several quarters with regard to the development of such a voltage level.

None of the utilities in the region appear to have any plans for the introduction of direct-current transmission. This undoubtedly reflects the already intensive and continuing development of an electrically-tight alternating current network. Direct-current transmission, of course, is not suitable for network application. It is possible, however, that some limited and special-purpose applications of direct-current transmission may develop in this area in the future.

The further strengthening of interregional interconnections is anticipated during the 1981–1990 period. This includes a 765-kV tie to the New York State-PJM area, additional 765-kV ties to Illinois, and a minimum of three new interconnections to the 500-kV systems in Pennsylvania, West Virginia, Maryland, and Virginia. Exhibit X.8 shows the number and voltage category of projected interconnections by 1990 with neighboring systems outside the East Central Region.

APPENDIX III–A

DEFINITION OF BITUMINOUS COAL AND LIGNITE PRODUCING DISTRICTS

DISTRICT 1.—EASTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All mines east of the Allegheny River, and those mines served by the Pittsburgh & Shawmut Railroad located on the west bank of the river.

Fayette County (part).—All mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines not served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties: Bedford, Blair, Bradford, Cambria, Cameron, Centre, Clarion, Clearfield, Clinton, Elk, Forest, Fulton, Huntingdon, Jefferson, Lycoming, McKean, Mifflin, Potter, Somerset, and Tioga.

Maryland.—All mines in the State.

West Virginia.—All mines in the following Counties: Grant, Mineral, and Tucker.

DISTRICT 2.—WESTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All mines west of the Allegheny River except those mines served by the Pittsburgh & Shawmut Railroad

Fayette County (part).—All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines except those served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties: Allegheny, Beaver, Butler, Greene, Lawrence, Mercer, Venango, and Washington.

DISTRICT 3.—NORTHERN WEST VIRGINIA

West Virginia.—Nicholas County (part).—All mines served by or north of the Baltimore & Ohio Railroad.

All mines in the following counties: Barbour, Braxton, Calhoun, Doddridge, Gilmer, Harrison, Jackson, Lewis, Marion, Monongalia, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tyler, Upshur, Webster, Wetzel, Wirt, and Wood.

DISTRICT 4.—OHIO

All mines in the State.

DISTRICT 5.—MICHIGAN

All mines in the State.

DISTRICT 6.—PANHANDLE

West Virginia.—All mines in the following counties: Brooke, Hancock, Marshall, and Ohio.

DISTRICT 7.—SOUTHERN NO. 1

West Virginia.—Fayette County (part).—All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake & Ohio Railroad and mines served by the Virginian Railway.

McDowell County (part).—All mines in that portion of the county served by the Dry Fork Branch of the Norfolk & Western Railroad and east thereof.

Raleigh County (part).—All mines except those on the Coal River Branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the main line and the Glen Rogers branch of the Virginian Railway.

All mines in the following counties: Greenbrier, Mercer, Monroe, Pocahontas, and Summers.

Virginia.—Buchanan County (part).—All mines in that portion of the county served by the

Richlands-Jewell Ridge branch of the Norfolk & Western Railroad and in that portion on the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek).

Tazewell County (part).—All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Montgomery, Pulaski, Wythe, Giles, and Craig.

DISTRICT 8.—SOUTHERN NO. 2

West Virginia.—Fayette County (part).—All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake & Co. Ohio Railroad.

McDowell County (part).—All mines west of and not served by the Dry Fork branch of the Norfolk & Western Railroad.

Nicholas County (part).—All mines in that part of the county south of and not served by the Baltimore & Ohio Railroad.

Raleigh County (part).—All mines on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway and lying west of the mouth of Skin Fork of Guyandot River.

All mines in the following counties: Boone, Cabell, Clay, Kanawha, Lincoln, Logan, Mason, Mingo, Putnam, and Wayne.

Virginia.—Buchanan County (part).—All mines in the county except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

Tazewell County (part).—All mines in the county except in those portions served by the Dry Fork branch of the Norfolk & Western Railroad and Branch from Bluestone Junction to Boissevain of Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Dickinson, Lee, Russell, Scott, and Wise.

Kentucky.—All mines in the following counties in eastern Kentucky: Bell, Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Leslie, Letcher, McCreary, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Wayne, and Whitley.

Tennessee.—All mines in the following counties: Anderson, Campbell, Claiborne, Cumberland, Fentress, Morgan, Overton, Roane, and Scott.

North Carolina.—All mines in the State.

DISTRICT 9.—WEST KENTUCKY

Kentucky.—All mines in the following counties in western Kentucky: Butler, Christian, Crittenden, Daviess, Hancock, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Simpson, Todd, Union, Warren, and Webster.

DISTRICT 10.—ILLINOIS

All mines in the State.

DISTRICT 11.—INDIANA

All mines in the State.

DISTRICT 12.—IOWA

All mines in the State.

DISTRICT 13.—SOUTHEASTERN

Alabama.—All mines in the State.

Georgia.—All mines in the following counties: Dade and Walker.

Tennessee.—All mines in the following counties: Bledsoe, Grundy, Hamilton, Marion, McMinn, Rhea, Sequatchie, Van Buren, Warren, and White.

DISTRICT 14.—ARKANSAS–OKLAHOMA

Arkansas.—All mines in the State.

Oklahoma.—All mines in the following counties: Haskell, Le Flore, and Sequoyah.

DISTRICT 15.—SOUTHWESTERN

Kansas.—All mines in the State.

Texas.—All mines in the State.

Missouri.—All mines in the State.

Oklahoma.—All mines in the following counties: Coal, Craig, Latimer, Muskogee, Okmulgee, Pittsburg, Rogers, Tulsa, and Wagoner.

DISTRICT 16.—NORTHERN COLORADO

All mines in the following counties in the State: Adams, Arapahoe, Boulder, Douglas, Elbert, El Paso, Jackson, Jefferson, Larimer, and Weld.

DISTRICT 17.—SOUTHERN COLORADO

Colorado.—All mines except those included in District 16.

New Mexico.—All mines except those included in District 18.

DISTRICT 18.—NEW MEXICO

New Mexico.—All mines in the following counties: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miguel, Santa Fe, and Socorro.

Arizona.—All mines in the State.

California.—All mines in the State.

DISTRICT 19.—WYOMING

Wyoming.—All mines in the State.

Idaho.—All mines in the State.

DISTRICT 20.—UTAH

All mines in the State.

DISTRICT 21.—NORTH DAKOTA–SOUTH DAKOTA

All mines in North Dakota and South Dakota.

DISTRICT 22.—MONTANA

All mines in the State.

DISTRICT 23.—WASHINGTON

Washington.—All mines in the State.

Oregon.—All mines in the State.

Alaska.—All mines in the State.

APPENDIX VII–A

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

Dated August 1, 1967
(Superseding East Central Area Reliability Coordination Agreement dated January 14, 1967.)

and

SUPPLEMENTAL AGREEMENT

Dated October 20, 1967

CONTENTS

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

SUPPLEMENTAL AGREEMENT

East Central Area Reliability Coordination Agreement, dated August 1, 1967, among Appalachian Power Company, The Cincinnati Gas & Electric Company, The Cleveland Electric Illuminating Company, Columbus and Southern Ohio Electric Company, The Dayton Power and Light Company, Duquesne Light Company, East Kentucky Rural Electric Cooperative Corporation, Indiana & Michigan Electric Company, Indiana-Kentucky Electric Corporation (*"IKEC"*), Indianapolis Power & Light Company, Kentucky Power Company, Kentucky Utilities Company, Louisville Gas and Electric Company, Monongahela Power Company, Northern Indiana Public Service Company, Ohio Edison Company, Ohio Power Company, Ohio Valley Electric Corporation (*"OVEC"*), Pennsylvania Power Company, The Potomac Edison Company, Public Service Company of Indiana, Inc., Southern Indiana Gas and Electric Company, The Toledo Edison Company, and West Penn Power Company,

Witnesseth:

0.01 Each of the parties owns an electric utility system engaged in the generation, transmission, and sale of electric power and energy in the East Central Area of the United States. They are hereinafter referred to collectively as the *"ECA Companies"*.

0.02 The systems of the ECA Companies are interconnected directly or indirectly and are operated in synchronism pursuant to a number of separate agreements among two or more of such companies.

0.03 The parties recognize that while many of the benefits of interconnected operation have accrued to each of them under existing agreements, the primary objective of bulk power supply reliability can be effectively achieved only among a manageable number of electric systems within a major area of reasonable geographical boundaries, in this instance the systems within the East Central Area, and through the mechanism of a well-defined organization with agreed-upon procedures for implementing this objective.

ARTICLE 1

Purpose of Agreement

1.01 The purpose of this Agreement is further to augment reliability of the parties' bulk power supply through coordination of the parties' planning and operation of their generation and transmission facilities.

ARTICLE 2

Executive Board

2.01 Each party by written notice to the others shall designate, and may change at any time, a person to act as its member on a group to be known as the Executive Board. OVEC and IKEC shall be represented by the same person. Other affiliated parties comprising single systems likewise shall be represented in each instance by the same person. Each party's member shall have authority to act for it in the administration of all matters pertaining to this Agreement and to perform such other duties as are hereinafter specified. The initial members of the Executive Board shall be appointed within fifteen days after the execution of this Agreement. Each member of the Executive Board may, at any time, designate an alternate to act for him.

2.02 The members of the Executive Board periodically will select one of their number to serve as Chairman, and one as Vice Chairman, each for a term not to exceed three years.

2.03 The members of the Executive Board shall meet quarterly and from time to time as required to carry out their duties. Meetings shall be called by the Chairman on his own initiative or upon request of two or more members of the Board. As far in advance of each meeting as practicable an agenda therefor shall be distributed to each member.

2.04 The Executive Board shall establish, within one year after the execution of this Agreement and thereafter periodically review, principles and procedures with respect to matters affecting the reliability of bulk power supply, including, but not limited to, minimum installed capacity and spinning reserves to be provided by each party by ownership or contract, the distribution of spinning reserves, coordination of generation and transmission maintenance, emergency measures, communications, protection, and the evaluation and simulated testing of systems' performance.

The Executive Board shall from time to time establish and periodically review such other principles and procedures as it may deem necessary for the purpose of this Agreement as set forth in *Article 1*.

2.05 Decisions of the Executive Board in any calendar year shall require the affirmative votes of members, or their alternates, representing parties to this Agreement whose non-coincident peak loads for the previous calendar year aggregated at least 95% of the total of such loads of all parties to this Agreement.

2.06 The expenses of each member of the Executive Board and his alternate shall be borne by the party or parties he represents. Any other expenses of the Executive Board shall be shared as agreed upon by the Board.

ARTICLE 3

Coordination Review Committee

3.01 Each party by written notice to the Executive Board shall designate, and may change at any time, a person to act as its member on a group to be known as the Coordination Review Committee. OVEC and IKEC shall be represented by the same person. Other affiliated parties comprising single systems likewise shall be represented in each instance by the same person. The initial members of the Coordination Review Committee shall be appointed within thirty days after the execution of this Agreement. Each member of the Coordination Review Committee may, at any time, designate an alternate to act for him.

3.02 The Executive Board periodically will select a member of the Coordination Review Committee to serve as Chairman, and one as Vice Chairman, of such Committee. The term of any Chairman, unless otherwise agreed to by the Executive Board, shall not exceed three years.

3.03 The Coordination Review Committee shall schedule a meeting for each calendar month and its members shall otherwise communicate with one another as required to carry out their duties. Meetings shall be called by the Chairman on his own initiative or upon request of two or more members of the Committee.

3.04 The Coordination Review Committee shall on a continuing basis:

(1) make recommendations to, and otherwise advise, the Executive Board with respect to the principles and procedures to be established by it pursuant to *Section 2.04;*

(2) in conjunction with each party, review and evaluate such party's planning for generation and transmission facilities and other matters relevant to the reliability of the ECA Companies' bulk power supply; and

(3) perform studies and investigations concerning over-all adequacy of transmission facilities, generation reserves, and operating practices and procedures and make recommendations to the Executive Board with respect thereto.

3.05 To enable the Coordination Review Committee to carry out its duties, the parties shall furnish said Committee such studies and data as it shall reasonably request, including but not limited to, technical studies of system performance under normal and abnormal conditions or under contingencies which would endanger service to major portions of the areas served by ECA Companies, and data on current and projected loads, system equipment capabilities, capability margins, spinning reserves, relay settings controlling major facilities, communications facilities, recording facilities and instructions to operating personnel. Except as otherwise authorized by the Executive Board, such studies and data shall be used solely for the purpose of carrying out the terms of this Agreement.

3.06 Committee recommendations pursuant to *Sections 3.04 (1)* and *(3)* shall be adopted, and other Committee action taken, by a two-thirds vote of the members. Dissenters may submit minority reports.

3.07 The expenses of each member of the Coordination Review Committee and his alternate shall be borne by the party or parties he represents. Any other expenses of the Committee shall be shared as agreed upon by the Executive Board.

ARTICLE 4

Advisory Panels

4.01 The Coordination Review Committee shall from time to time appoint Advisory Panels of technical experts to assist the Committee in carrying out its duties. Within forty-five days after the execution of this Agreement the Committee shall appoint a System Reliability Advisory Panel, a Generation Advisory Panel, a Transmission Advisory Panel, a Protection Advisory Panel, and an Operation Advisory Panel. Appointments to the Advisory Panels shall be subject to the approval of the Executive Board.

4.02 Each Advisory Panel shall consist of not more than seven members. The Coordination Review Committee shall advise the parties in writing of the persons who are to act as members of each Advisory Panel. Each member of an Advisory Panel may, at any time, designate an alternate to act for him in the event of his incapacity.

4.03 The Coordination Review Committee will select a member of each Panel to serve as Chairman of such Panel. The term of any Chairman, unless otherwise agreed to unanimously by the Coordination Review Committee, shall not exceed three years.

4.04 The specific duties of each Panel shall be determined by the Coordination Review Committee, and a written description thereof shall be furnished to each member of such Panel and to the Executive Board.

4.05 The expenses of each member of an Advisory Panel shall be borne by the party by whom he is regularly employed. Any other expenses of a Panel shall be shared as agreed upon by the Executive Board.

ARTICLE 5

Executive Manager

5.01 The Executive Board shall within forty-five days after the execution of this Agreement appoint an Executive Manager who under the direction of the Chairman of the Coordination Review Committee shall, on a full-time basis:

(1) keep fully informed with respect to matters affecting bulk power reliability in the ECA Companies' area,

(2) assist the ECA Companies in following and carrying out the principles and procedures established by the Executive Board pursuant to *Section 2.04,*

(3) assist the Coordination Review Committee and its Advisory Panels by furnishing data and suggestions based on his observations of system performance and in general assist the Committee in carrying out its duties under *Section 3.04,*

(4) collect, consolidate, analyze, and distribute studies and data pertinent to his responsibilities furnished the Coordination Review Committee pursuant to *Section 3.05,* and

(5) perform such other duties as shall be set forth in a job description approved by the Executive Board.

5.02 Quarters shall be provided for the Executive Manager and his staff at a place within the East Central Area to be selected by the Executive Board.

5.03 The salaries and office expenses of the Executive Manager and his staff shall be shared as agreed upon by the Executive Board.

ARTICLE 6

Inter-Area Coordination

6.01 The parties recognize that attainment of their objectives requires continued cooperation between them and other companies outside the East Central Area and particularly cooperation between the parties hereto and companies outside the Area with whose systems they are directly interconnected. Accordingly, the ECA Companies will endeavor to bring about periodic reviews with coordinated areas contiguous to the East Central Area of generation and transmission expansion programs and systems performance to the end of further augmenting reliability of bulk power supply for all. In this connection the parties will attempt to establish liaison arrangements between the Coordination Review Committee and authorized groups in coordinated areas contiguous with the East Central Area.

ARTICLE 7

Term

7.01 This Agreement shall continue for five years from its date and thereafter until terminated by unanimous agreement of the parties, but any party to this Agreement may cease to be such by giving the others at least 30 days written notice of its intention. Any such party shall nevertheless continue to be liable for its share of expenses incurred prior to the end of the calendar year in which such notice is given.

ARTICLE 8

General

8.01 No party shall be liable for the failure of any other party to perform its obligations hereunder.

8.02 Each party shall retain sole control over its own facilities and the use thereof.

8.03 This Agreement supersedes the East Central Area Reliability Coordination Agreement dated January 14, 1967, among all of the parties hereto except East Kentucky Rural Electric Cooperative Corporation.

ARTICLE 9

Assignment

9.01 Any party may assign this Agreement to a successor corporation acquiring its property and business substantially as an entirety, provided such successor corporation assumes all obligations of the assignor under this Agreement. Except as aforesaid no party shall assign this Agreement without the prior written consent of the other parties.

ARTICLE 10

Additional Arrangements

10.01 Each ECA company will study the possibility of additional arrangements between its system and one or more systems of ECA Companies contiguous with its own that will contribute to achieving the objective of the parties to render reliable service and that will also contribute to operating economies to the fullest extent consistent with that objective. Such arrangements pertain, among other things, to such matters as ownership and operation of generation and transmission facilities, mutual assistance, and interchanges of electric capacity and energy for improvement of service and economy.

ARTICLE 11

Regulation

11.01 This Agreement is subject to the approval of all regulatory authorities having jurisdiction in the premises.

In Witness Whereof, the parties hereto have caused this Agreement to be duly executed.

Appalachian Power Company
Donald C. Cook
President

The Cincinnati Gas & Electric Company
Wm. H. Zimmer
President

The Cleveland Electric Illuminating Company
K. H. Rudolph
President

Columbus and Southern Ohio Electric Company
J. L. McNealey
President

The Dayton Power and Light Company
J. M. Stuart
President

Duquesne Light Company
Philip A. Fleger
Chairman

East Kentucky Rural Electric Cooperative Corporation
Alex B. Veech
President

Indiana & Michigan Electric Company
Donald C. Cook
President

Indiana-Kentucky Electric Corporation
Philip Sporn
President

Indianapolis Power & Light Company
Ottis T. Fitzwater
Chairman

Kentucky Power Company
Donald C. Cook
President

Kentucky Utilities Company
W. A. Duncan
President

Louisville Gas and Electric Company
B. Hudson Milner
President

Monongahela Power Company
C. G. McVay
President

Northern Indiana Public Service Company
Dean H. Mitchell
President

Ohio Edison Company
D. Bruce Mansfield
President

Ohio Power Company
Donald C. Cook
President

Ohio Valley Electric Corporation
Philip Sporn
President

Pennsylvania Power Company
D. Bruce Mansfield
President

The Potomac Edison Company
C. D. Lyon
President

Public Service Company of Indiana, Inc.
C. H. Blanchar
President

Southern Indiana Gas and Electric Company
A. B. Brown
President

The Toledo Edison Company
John K. Davis
President

West Penn Power Company
R. G. MacDonald
President

Supplemental Agreement, dated October 20, 1967, among the undersigned electric utility companies, supplementing the East Central Area Reliability Coordination Agreement, dated August 1, 1967, (the *"ECAR Agreement"*) among the parties hereto other than Consumers Power Company (*"Consumers"*) and The Detroit Edison Company (*"Detroit Edison"*),

Witnesseth:

0.01 The systems of the parties to the ECAR Agreement and those of Consumers and Detroit Edison will be interconnected directly or indirectly and operated in synchronism pursuant to separate agreements among two or more of such companies upon the completion, scheduled for mid-1969, of facilities now under construction; and the performance of the Consumers and Detroit Edison systems will then have a significant effect on the reliability of the bulk power supply of the parties to the ECAR Agreement. In anticipation of this situation the parties hereto desire that Consumers and Detroit Edison become parties to the ECAR Agreement as soon as possible.

ARTICLE I

1.01 Consumers and Detroit Edison shall each become a party to the ECAR Agreement on November 1, 1967, and the provisions of the ECAR Agreement shall thereafter inure to the benefit of and be binding upon each of said companies.

In Witness Whereof, the parties hereto have caused this Supplemental Agreement to be duly executed.

Appalachian Power Company
Donald C. Cook
President

The Cincinnati Gas & Electric Company
Wm. H. Zimmer
President

The Cleveland Electric Illuminating Company
K. H. Rudolph
President

Columbus and Southern Ohio Electric Company
J. L. McNealey
President

Consumers Power Company
A. H. Aymond
Chairman

The Dayton Power and Light Company
J. M. Stuart
President

The Detroit Edison Company
Walker L. Cisler
Chairman
Duquesne Light Company
Philip A. Fleger
Chairman and
Chief Executive Officer
East Kentucky Rural Electric Cooperative Corporation
Alex B. Veech
President
Indiana & Michigan Electric Company
Donald C. Cook
President
Indiana-Kentucky Electric Corporation
Donald C. Cook
President
Indianapolis Power & Light Company
Ottis T. Fitzwater
Chairman
Kentucky Power Company
Donald C. Cook
President
Kentucky Utilities Company
W. A. Duncan
President
Louisville Gas and Electric Company
B. Hudson Milner
President
Monongahela Power Company
F. J. McAlary
Vice President
Northern Indiana Public Service Company
Dean H. Mitchell
Chairman
Ohio Edison Company
D. Bruce Mansfield
President
Ohio Power Company
Donald C. Cook
President
Ohio Valley Electric Corporation
Donald C. Cook
President
Pennsylvania Power Company
D. Bruce Mansfield
President
The Potomac Edison Company
E. W. Wilkinson
Vice President
Public Service Company of Indiana, Inc.
C. H. Blanchar
President
Southern Indiana Gas and Electric Company
A. B. Brown
President
The Toledo Edison Company
John K. Davis
President
West Penn Power Company
Charles B. Finch
Vice President

APPENDIX VII–B [1]

COORDINATED PLANNING AND DEVELOPMENT—POWER SYSTEMS IN THE EAST CENTRAL REGION

In accordance with the "Guidelines for Study of Coordinated Planning and Development by Regions" as developed by the Federal Power Commission Staff, the East Central Regional Advisory Committee has compiled information as to the structure and functioning of all coordinating groups within the East Central Region. The information requested of each group was as follows:

1. Type of organization (holding company, planning group, or planning and operating pool, etc.)
2. History of development.
3. List of members.
4. Requirements for participation.
5. Organizational structure including official positions, any committees and their functions, and methods of arriving at decisions affecting members of the coordinating group.
6. Practices in the planning and development of facilities, including:
   a. Coordinated load projections.
   b. Coordinated planning for reserves.
   c. Coordinated system stability studies.
   d. Joint or staggered participation in facilities development.
7. Operating practices, including:
   a. Exchanges of capacity and energy.
   b. Coordination of reserves, including spinning reserves.
   c. Coordination of maintenance.
   d. Economic dispatch, including description of control facilities.

The requested information for each group in the East Central Region is shown in the attached sections of this appendix. The index to these sections and the companies included within each group is as follows:

INDEX TO REPORTS

Pool or system	Companies	Section
APS	Monongahela Power Co.	A
	The Potomac Edison Co.	
	West Penn Power Co.	
AEP [2]	Appalachian Power Co.	B
	Indiana & Michigan Electric Co.	
	Kentucky Power Co.	
	Kingsport Power Co.	
	Ohio Power Co.	
	Wheeling Electric Co.	
CAPCO	The Cleveland Electric Illuminating Co.	C
	Duquesne Light Co.	
	Ohio Edison Co.	
	Pennsylvania Power Co.	
	The Toledo Edison Co.	

[2] Since the preparation of this material, the Michigan Power Company (formerly Michigan Gas and Electric Company), has become a subsidiary of the AEP System.

[1] August 1968 (Revised April 1969).

Section A—Coordinated Planning and Development—APS

1. *Reporting Organization*

   a. Allegheny Power System, Inc.
   320 Park Avenue, New York, N.Y. 10022

   Type of Organization

   b. An electric utility holding company.

2. *History of Development*

Allegheny Power System was formed in 1925 under the name of The West Penn Electric Company to hold the securities of its present three major electric subsidiaries which previously had been assembled under the control of the American Water Works and Electric Company, Incorporated. No substantial acquisitions of operating electric properties occurred after 1923.

In 1947, American Water Works and Electric Company, Incorporated, carried out its segregation and liquidation plans under the Public Utility Holding Company Act of 1935. This brought about the distribution in 1948 of all of the common stock of The West Penn Electric Company to the holders of the common stock of its former parent.

The change of name from The West Penn Electric Company to Allegheny Power System, Inc. occurred in 1960.

3. *List of Members*

The companies in the holding company of Allegheny Power System, Inc. include Monongahela Power Company, The Potomac Edison Company, West Penn Power Company, Allegheny Power Service Corporation, and their respective subsidiaries.

4. *Requirements for Participation*

Common ownership.

5. *Organizational Structure*

Allegheny Power System, Inc. (Allegheny) is the parent company in the integrated electric System comprising the properties of Monongahela Power Company, The Potomac Edison Company, West Penn Power Company, and their subsidiaries. As such, it is the owner of the operating companies in the System and is the vehicle through which equity capital for the System is obtained.

As a matter of basic policy, the System is operated to realize the advantages of the integrated System to the fullest extent consistent with proper recognition of applicable local law and local regulatory requirements. Accordingly, each operating company in the System operates within the framework of the integrated System. Within this basic policy the prin-

ciple of decentralization is followed. This principle places on each of the operating companies responsibility for operations and operating results.

The operation of the Allegheny Power System on an integrated basis results in economies and other advantages in matters such as: (1) pooling available, generating and transmission capacity, (2) planning additions to generating and transmission capacity, (3) cooperating in activities of mutual interest, (4) exchanging technical knowhow, experience and information to improve methods and the quality and dependability of service, and (5) attracting, training and holding skilled personnel. To realize such advantages, Allegheny Power System, Inc. and the electric utility operating companies in the Allegheny Power System have entered into service contracts with Allegheny Power Service Corporation (Service Company), a wholly-owned subsidiary of Allegheny Power System, Inc., the effect of which is to give the Service Company responsibility and accountability for coordinating the operations of the System as a whole and for matters and policies of System-wide applicability.

System Committees are used to facilitate the successful operation of the integrated System. They have no operating responsibilities and no authority to make decisions. They serve to increase management effectiveness in the following respects:

(1) Communication: All of the Committees serve as means of communication. They provide a channel through which specialists in the same fields can share knowledge, experience and information on related activities. In this way they facilitate the System-wide application of worthwhile improvements developed in any one of the System companies.

(2) Uniformity of practices: Some Committees explore the possibility and desirability of achieving greater uniformity of practices throughout the System.

(3) Problem solving: Some Committees are assigned particular problems of System significance. In such instances, the assignment of the Committee is simply to explore and make recommendations.

The System Facilities Planning Committee and the Power Supply Committee, along with their subcommittees, are the ones principally concerned with coordinating power supply matters.

A brief synopsis of some of the committees and functions follows:

System Facilities Planning Committee

To undertake studies and develop recommendations in regard to requirements for generating capacity additions and retirements, new major transmission lines, and interconnections with nonaffiliated companies, and to review forecasts of future loads and budget items for major transmission facilities.

To plan and coordinate the work of its Subcommittees which report their findings and recommendations to it. This Committee has two Subcommittees: Transmission and Generating Facilities.

Transmission Facilities Subcommittee

To make studies assigned by the System Facilities Planning Committee to assist in the development of plans on transmission and interconnection facilities for Allegheny Power System.

To keep the System Facilities Planning Committee informed on current practices affecting System planning of major transmission and interconnections and any new tools or techniques appropriate for planning purposes.

To recommend to the System Facilities Planning Committee load flow and stability studies as required for the Allegheny Power System and outside Systems.

To oversee the work of the Subgroup on Controls, Relaying and Communications.

Generating Facilities Subcommittee

To make studies assigned by the System Facilities Planning Committee to assist in the development of plans for generating units for Allegheny Power System.

To study, investigate and report on generating methods and associated devices which have promise for future use on the APS system, including nuclear, nonsteam thermal, conventional and pumped storage hydro.

To consider and set up systems whereby correct and uniform data is easily available to those working on system generating problems and to develop in advance of use procedures for solutions to repetitive problems arising in system generating planning work.

To investigate and determine for the System Facilities Planning Committee locations and suitability of possible sites for power generating stations for the Allegheny Power System power supply.

To make recommendations for the purchase of acreage for future station construction to the System Facilities Planning Committee. This acreage is not necessarily limited to that within the service area.

To prepare and maintain up-to-date records of data on sites owned by Allegheny Power System companies and others, suitable for location of Allegheny Power System generating stations.

To oversee the work of the Subgroup on Fuel.

Power Supply Committee

To assist in obtaining those advantages which result from coordination and review of APS power supply matters. In performing such functions it

(1) develops plans and programs to improve efficiency and operating results of APS power stations, including planning of personnel requirements for major power stations,

(2) develops, recommends, and reviews policies and procedures concerning the operation of the APS power supply facilities,

(3) oversees the administration of the Power Supply Agreement,

(4) reviews existing and proposed power sales, purchases, and operating agreements to insure APS can meet adequately its commitments and that arrangements with outside systems are such as to maintain desirable conditions within APS.

To plan, coordinate and approve the work of its subcommittees which report their findings and recommendations to it. Two subcommittees, Subcommittee on Power Production and Subcommittee on Operating and Interchange Billing, report to this committee.

There is representation on these committees of interested people from each company and their recommendations are forwarded to the Presidents for approval.

6. *Practices in the Planning and Development of Facilities*

   a. *Coordinated load predictions*

      A Load Prediction Committee generates short- and long-range predictions updated twice a year or oftener for approval by the Presidents.

   b. *Coordinated planning for reserves*

      All reserves are planned by the System Facilities Planning Committee.

   c. *Coordinated system stability studies*

      A function of the Transmission Facilities Subcommittee.

   d. *Joint facilities development*

      Same as (b) above.

7. *Operating Practices.* (These functions are all reviewed by the Power Supply Committee)

   a. *Exchange of capacity and energy*

      Intercompany Power Agreement between companies of system provides for central loading of system by one of the operating companies.

   b. *Coordination of reserves*

      Reserves are set up centrally.

   c. *Coordination of maintenance*

      Maintenance scheduling is done centrally.

   d. *Economic dispatch*

      Economic dispatch is done centrally for the system with a Westinghouse digital computer.

General

Allegheny Power System, Inc. or its subsidiaries has contracts for interconnection and purchase and sale of capacity and energy with American Electric Power companies, Pennsylvania-Jersey-Maryland companies, Ohio Edison Company and its subsidiary, Virginia Electric and Power Company, and Duquesne Light Company. Under the contracts operating and planning committees coordinate the long-range planning and day-to-day operation between each company. Participation in joint transmission load flow and stability studies, coordinated maintenance, and daily scheduling of interchanges of capacity and energy are typical of the relationships which exist. A part of the mutual effort includes also the interchange of load forecasts and capacity data, as well as other study information which might be helpful in providing more reliable and economic service to our customers. Examples of this relationship include ownership of Windsor Power Station with Ohio Power (AEP) and ownership of Fort Martin with Duquesne Light (DL).

Allegheny Power System, Inc. also owns 12½% of the capital stock of Ohio Valley Electric Corporation (OVEC). Allegheny Power System is represented on the OVEC Board.

The subsidiary operating companies of Allegheny Power System are parties to the "East Central

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Area Reliability Coordination Agreement"—"ECAR". The purpose of ECAR is to further augment reliability of the parties' bulk power supply through coordination of the parties' planning and operation of their generation and transmission facilities. A complete description of this organization will be supplied in another part of the Regional report.

Section B—Coordinated Planning and Development—AEP

1. *Reporting Organization*
   a. American Electric Power Company
      2 Broadway, New York, N.Y.

   Type of Organization.

   b. An electric utility holding company.
2. *History of Development*

The American Electric Power Company is an electric utility holding company comprising seven wholly-owned subsidiary companies operating in parts of the seven states of Ohio, Indiana, Michigan, Virginia, West Virginia, Kentucky and Tennessee.

The American Electric Power Company was founded in 1906 as the American Gas and Electric Company. Its history of growth has been characterized by the acquisition of small utilities, operating in local communities or limited areas, and the integration of their electric facilities through the early development of an extensive transmission network, accompanied by the sale and disposal of their gas, traction and other non-electric facilities. This has permitted the realization of successive economies of scale and improved levels of reliability which, in turn has stimulated further growth within the area served.

The integrated nature of the AG&E System with the evident benefits and economies derived therefrom was the basis for its approval under the Public Utilities Holding Company Act of 1935.

In 1958 the name of the company was changed from American Gas & Electric Company to American Electric Power Company in order better to reflect the true nature of its business.

3. *List of Members*

The principal operating companies comprising the AEP System are: Ohio Power Company, Indiana & Michigan Electric Company, Appalachian Power Company, Kentucky Power Company, Wheeling Electric Company, Kingsport Power Company, and Michigan Power Companv. In addition, the American Electric Power Service Corporation has been established, as a subsidiary of the AEP Company, to furnish engineering and other specialized services to the operating companies.

4. *Requirements for Participation*

Common ownership.

5. *Organizational Structure*

The American Electric Power Company System, while comprising seven principal operating companies, functions as a single, integrated power system. This objective is accomplished administratively by the fact that the president of the parent company is also the president of each of the operating subsidiaries, as well as of AEP Service Corporation.

The AEP Service Corporation, with its main offices in New York and a branch office in Canton, Ohio, provides the technological leadership and skill for the entire AEP System. It carries out the planning of all generation, interconnection, transmission, subtransmission and related facilities. It is responsible for the design and overseas construction of all generation and transmission. It orders all major equipment, establishes design and construction standards, guides the development of major distribution improvement programs and conducts research. It also operates the System Power Production and Control office in Canton, Ohio, which is reponsible for the minute-to-minute operation of the AEP System.

Periodic meetings among Service Corporation and operating company personnel, together with field trips, permit the necessary interchange of ideas, collection of data and review of problems to assure the effective development of system plans, programs and procedures.

The centralization of primary responsibility for the planning, engineering, design, construction and operation of major generation and transmission within the Service Corporation and its field organizations, i.e., Canton Engineering Office and System Power Production and Control office, assures the most economical and reliable design and operation of the AEP System as an integrated unit. Furthermore this arrangement permits the development of uniform standards of design and performance for all categories of facilities and service throughout the system.

6. *Practices in the Planning and Development of Facilities*

a. *Coordinated load projections*

Load projections of the AEP System are made by the Service Corporation on both an overall system and intrasystem area basis. The former recognize both area growth possibilities and general economic factors. The latter are arrived at following detailed discussion and study with field personnel. The area and system projections are coordinated by the Service Corporation for planning and operating purposes.

b. *Coordinated planning for reserves*

Since the AEP System is planned and operated as well as economically dispatched, as one integrated entity, generation reserves are provided on a systemwide basis. These reserves are continually under study, taking into account trends in load growth, equipment outage experience, interruptible loads, emergency overload capabilities of units and most importantly the contribution of interconnections. In view of the 76 interconnections at 138 kV, 345 kV and 500 kV now in service between the AEP System and neighboring utilities, with an additional 18 interconnections now under construction (2 at 138 kV, 12 at 345 kV, 2 at 500 kV and 2 at 765 kV), the effectiveness of emergency support during emergencies is a major factor in determining required generation reserves. Specific kilowatt commitments in all AEP interconnection agreements, together with actual experience in interconnected performance, which is continually reviewed, have provided a reliable indication of the degree of emergency support from interconnections which can be expected. The development of interconnections and interconnection agreements over a period of many years has permitted a major degree of coordination of reserve planning by AEP and its neighbors.

c. *Coordinated system stability studies*

In addition to its own internal stability studies, the AEP System has entered into numerous stability studies with individual utilities and groups of interconnected utilities from time to time. These studies have been directed toward determining the effects of new or projected facilities of one system upon another, the expected performance of new interconnections, and the consequences of major disturbances, including transmission outages, loss of load and loss of generation. Studies of this kind must and have been done on a coordinated basis, including all utilities upon which the studies in question would have an effect.

d. *Joint or staggered participation in facilities development*

The AEP System has a long history of participation with other utilities in facilities development. The oldest such example is the joint construction of the Windsor Plant on the Ohio River in 1916–1917 with the West Penn Power Company. This remains one of the oldest examples of this kind in the United States.

The most outstanding example was the establishment of the Ohio Valley Electric Corporation (OVEC) and its subsidiary company, Indiana-Kentucky Electric Corporation (IKEC), for the supply of about 1,800 MW to the Atomic Energy Commission's gaseous diffusion plant near Portsmouth, Ohio. This project, placed in operation in 1955–56, involved the construction of two major generating plants, extensive 345-kV transmission and numerous interconnections with adjoining systems. This cooperative enterprise involved 15 utility operating companies, including three companies of the AEP System. Other examples of joint or staggered participation in facilities may be found in the development of numerous interconnection arrangements between AEP and neighboring utilities. Two of the most recent are: in terms of generation, the joint Buckeye Power (a group of Ohio cooperatives)—Ohio Power 1,230 MW Cardinal plant now completed and in operation and, in terms of transmission, the Tidd-Wylie Ridge-Sammis 345-kV coordinated transmission development among the Ohio Power Company, Monongahela Power Company (APS) and Ohio Edison Company and, in addition, a similar project involving the construction of 345-kV transmission on a coordinated basis among the Indiana & Michigan Electric Company (AEP), Consumers Power Company, Detroit Edison Company, Toledo Edison Company and the Ohio Power Company (AEP).

7. *Operation Practices*

a. *Exchange of capacity and energy*

The AEP System has a long history of capacity and energy exchanges. These take the form of long-range, firm power sales to other utilities as well as interim and short-term sales and purchases. In addition, large amounts of economy energy are interchanged. In two instances, diversity power is also interchanged.

b. *Coordination of reserves*

Installed reserves are coordinated by the AEP System with other power systems by means of two-party interconnection agreements, each of which provides for emergency exchange in specifically guaranteed amounts. This permits the reduction in installed reserves which constitutes one of the fundamental objectives of interconnections. Spinning reserves are coordinated in daily operation by the AEP System Power Coordinator with other power systems, within the framework of ECAR recommended practices.

c. *Coordination of maintenance*

Maintenance coordination is covered in all AEP interconnection agreements with a provision for specific amounts of power and annual energy interchange for that purpose. In addition to bi-party coordination of generation maintenance, AEP as a participant in ECAR exchanges information with the other participants so as to optimize maintenance coordination where possible and to minimize simultaneous outages of equipment on the combined systems.

d. *Economic dispatch*

Economic dispatch is carried out for the entire AEP System by the Power Production and Control office. The computer facilities at Canton comprise an L&N—IBM combination of analog and digital equipment, respectively. The load-frequency control function is essentially assigned to the L&N computer with the economic dispatch calculation carried out every 2 to 3 minutes on the IBM computer.

General

In addition to its long history of coordination with other utilities in the areas of both planning and operation through the medium of two-party contracts or multi-party contracts, e.g. OVEC, the AEP System is a participant in ECAR and has liaison membership in MAIN. As such, the AEP System interchanges information concerning load, generation and transmission projections and participates in joint studies, all in an attempt to continue to seek improvements in the reliability and economy of its performance.

Section C—Coordinated Planning and Development—CAPCO

1. *Type of Organization*

Central Area Power Coordination Group (CAPCO) is a coordinating group with activities in two principal areas: planning and operation.

2. *History of Development*

CAPCO originally formed on December 1, 1964, now consists of five major investor-owned electric utilities providing service in Northern Ohio and Western Pennsylvania. All of the utilities have had a long history of participation in the coordination of system development and operation. Prior to the formation of CAPCO, coordination of activities was being fostered by an informal group known as the North Central Area—Eastern Pool Group.

3. *List of Members*

The Cleveland Electric Illuminating Company
Duquesne Light Company
Ohio Edison Company
Pennsylvania Power Company
The Toledo Edison Company

4. *Requirements for Participation*

Consent of all parties to the Agreement.

5. *Organizational Structure*

The CAPCO organization is headed up by an Executive Committee, composed of top executives of the Member Companies, which is responsible for the basic policy and for fostering development of new opportunities for mutual benefit. The Executive Committee is responsible for recommending such transactions, principles, procedures, rules or programs as it considers will further the purpose of this Agreement.

6. *Practices in the Planning and Development of Facilities*

Activities of the CAPCO group have included the following:

a. *Coordinated load projections*

A procedure and format was developed and is being used for the compilation and reporting of generation and load data. This data will be reviewed and updated annually.

b. *Coordinated planning for reserves*

A working group has explored the development of a method for the analysis of reserves within CAPCO and has explored methods of evaluating transmission capabilities.

c. *Coordinated system stability studies*

A working group analyzed and evaluated the performance of the present CAPCO systems under severe emergency conditions. This activity was subsequently taken over by ECAR.

d. *Joint or staggered participation in facilities development*

Two joint projects involving the CAPCO group are being carried out. One such project between Duquesne Light and Allegheny Power System involves joint ownership of a 540 MW generating unit. Another project of this type between Ohio Edison Company and The Cleveland Electric Illuminating Company, involves the installation of two 600 MW units of additional generating capacity by 1970. The first unit which came into service in early 1969 is on the Ohio Edison system, while the second unit, expected to be in service by June 1, 1970, will be on the Illuminating Company's system. The two systems will share equally the output of the Ohio Edison unit until June 1, 1970, and until 1983 each system will provide back-up for one half of the other's unit. Additional 345-kV interconnecting lines between the companies are included in the project.

e. *Pooling arrangement*

A pooling arrangement among the companies was entered into on September 14, 1967. This involves the coordination of the installation of generating and transmission capacity on the systems of the parties. The initial program consists of the installation of two 625 MW units, one in 1971 and one in 1972 and two 800 MW units, one in 1973 and one in 1974. In addition certain pooled transmission facilities will be built.

7. *Operating Practices*

a. *Exchange of capacity and energy*

Exchange of capacity and energy is carried out according to the terms of agreements between the companies involved.

b. *Coordination of reserves including spinning reserves*

A study has been initiated to review spinning reserve practices and to determine the speed of response of systems during periods of rapid load change and emergency.

c. *Coordination of maintenance*

This activity has been practiced for many years by the CAPCO companies. To facilitate coordination, a working group has developed a standard system of monthly reporting of maintenance schedules and net margins. Quarterly meetings have been set up to review overall net margins and revise schedules to levelize net margins.

d. *Economic dispatch including description of control facilities*

Within the CAPCO group economic dispatch is being carried out by the individual companies or by the integrated systems utilizing in many cases digital or analog computers.

Section D—Coordinated Planning and Development—CCD

1. *Type of Organization*

The CCD group is comprised of three separate companies who have agreed to coordinate their generation and transmission planning and to build as tenants in common certain generation and bulk transmission facilities in which each company will own a specified undivided share. These facilities will be operated under agreements mutually acceptable to the companies.

2. *History of Development*

On June 22, 1962 the three companies, through a Declaration of Intent, agreed to plan together for

the development of the most effective power systems to provide a high order or economical and reliable power supply to the many communities and consumers they serve. As a result of this Declaration of Intent these companies have now agreed to build, as tenants in common, additional large units with net generating capacity totaling 3,560,000 kW at an estimated cost of $460,000,000, at four different sites, and 415 miles of 345 kV high voltage transmission lines and associated substation facilities at a cost of $59,415,000. In addition, as further reliability insurance these companies, either as tenants in common or individually, have installed or have on order for early installation peaking, quick-start-up diesel or gas turbine type generating facilities totaling 323,000 kW at strategic locations.

Individually, these companies have installed or have active plans for early installation within their respective service areas, a total of 185 miles of additional 345 kV transmission lines and associated substation facilities at an estimated cost of $42,440,000.

These plans provide for commonly owned generating capacity needs through the anticipated summer peak of 1975. An additional estimated 216 miles of commonly owned 345 kV lines will be needed to take care of the power to be generated at the generating units to be installed in 1973 and 1975 (1,380,000 kW). These lines are now being studied and will be planned and provided for in ample time to meet the need.

All of the above plans have been coordinated with the generation and transmission construction plans of other companies adjoining the areas of the companies.

3. *List of Members*

The Cincinnati Gas & Electric Company
139 East Fourth Street
Cincinnati, Ohio 45201

Columbus and Southern Ohio Electric Company
215 N. Front Street
Columbus, Ohio 43215

The Dayton Power and Light Company
25 N. Main Street
Dayton, Ohio 45401

4. *Requirements for Participation*

There are no formal requirements for participation. The Declaration of Intent signed by the three companies sets out the basic aims. By mutual agreement through Memoranda of Understanding and other Basic Agreements, the companies have implemented this Declaration.

5. *Organizational Structure*

There is no organizational structure. It is a group of three companies whose representatives meet from time to time to discuss common power supply and transmission problems and the planning therefor. Recommendations are made by these representatives which, to become effective, must be unanimously approved by the managements of the companies.

6. *Practices in the Planning and Development of Facilities*

a. Load projections and forecasts of the three companies are coordinated.
b. The Companies will establish a minimum reserve standard and have agreed on equalization of reserves.
c. Many system stability and power flow studies have been and are being made by the companies together with the neighboring companies, and with the ECAR group of companies in order to coordinate transmission planning.
d. The three companies participate in facilities development as tenants in common. Their participation is neither staggered nor joint.

7. *Operating Practices*

Agreement has been reached that:

a. There will be exchanges of capacity and energy (as in the past, but more thoroughly coordinated).
b. There will be coordination of reserves, including spinning reserves, and exchanges of capacity in order to equalize reserves.
c. There will be coordination of maintenance (as in the past).
d. Consideration is being given to economic dispatch.

Section E—Coordinated Planning and Operations (Kentucky-Indiana Pool)

1. *Reporting Organization*

The Kentucky-Indiana Pool.

Type of Organization

Planning and Operating Pool.

2. *History of Development*

Since the Kentucky-Indiana Pool is an outgrowth of the Indiana Pool, the history of the Indiana Pool will be traced first.

A. The Indiana Pool

The Indianapolis Power & Light Company and Public Service Indiana are investor-owned companies which operate in 68 of the 92 Indiana counties. They have been interconnected for a number of years and have each received certain operating benefits through an interconnection agreement.

In May 1962, a new interconnection agreement between the two companies was signed which provided for operating benefits in addition to those provided in the original interconnection agreement and also provided for certain transmission facilities of benefit to both companies.

Since Indianapolis Power & Light Company experiences a summer peak and Public Service Indiana experiences a winter peak, an amount of diversity power was available to be exchanged between the companies during these seasonal periods. In December of 1962, a Seasonal Power Exchange Agreement was signed which provided for the exchange of this diversity power.

The Indiana pool proper was created in April 1964 by the signing of the Indiana Pooling Agreement. The Indiana Pooling Agreement includes some of the provisions of the Seasonal Power Exchange Agreement, but operating provisions were excluded since they were previously set forth in the interconnection agreement. Perhaps the one most significant feature of this agreement is its "one system" approach to generation and transmission expansion.

The Indiana Pool operation commenced May 1, 1967, shortly before Indianapolis Power & Light's Petersburg No. 1 unit went into commercial operation.

B. The Kentucky-Indiana Pool

The Kentucky Utilities Company is an investor-owned company which operates in 78 of the 120 Kentucky counties and 5 of the 98 Virginia counties. While not directly interconnected at present to either the facilities of Public Service of Indiana or Indianapolis Power and Light, transmission lines are so situated that such interconnection is not difficult.

In May 1967 a letter of intent was signed by Indianapolis Power & Light Company, Kentucky Utilities Company and Public Service Company of Indiana, Inc. to form the Kentucky-Indiana Pool to be known as KIP. The pooling and operating agreement among the three companies was signed on September 5, 1968. Preparation of a facilities agreement to allocate interconnection costs is under way at present.

The Kentucky-Indiana Pool will commence operations on May 1, 1970, when Public Service Indiana's Cayuga No. 1 unit goes into commercial operation. Coordinated planning for the pool has been proceeding using the principles of the Indiana Pooling agreement following the signing of the letter of intent in May 1967. General principles for planning and operations in KIP are expected to be much the same as are now provided by the planning and interconnection agreements of the Indiana Pool.

3. *List of Members*

Kentucky Utilities Company, a Kentucky Corporation, and Indianapolis Power & Light Company and Public Service Company of Indiana, Inc., both Indiana corporations, are the members of the Kentucky-Indiana Pool.

4. *Requirements for Participation*

Acceptance of the provisions of the Kentucky-Indiana Planning and Operating Agreement and facilities available for ready interconnection to one of the members of the pool if not already so interconnected.

5. *Organizational Structure*

The formation of the Kentucky-Indiana Pool will not change the organizational structure of any of the operating companies. The KIP Planning and Operating Agreement is expected to establish only two committees, a Planning Committee and an Operating Committee. Their foreseen general functions are outlined below:

Planning Committee

This Committee will operate under a one-system approach in planning the installation of generating units, purchases of firm power and installation of new transmission facilities and interconnections. This committee will generally:

a. agree upon power plant capability determinations

b. agree upon purchased power and power sales classifications

c. set up accounting procedures for billing pool transactions

d. establish long-range maintenance schedules

e. review adequacy of transmission facilities of the companies

f. review the expected future load growth of each company's system

g. make recommendations to the chief executives of the companies with respect to added reserves and pool transmission facilities required to meet such load growth.

The chief executives are expected to act upon the recommendations of the Planning Committee by an exchange of letters mutually agreeing to the best manner for the companies to increase the pool reserve (by installing generating capacity or by the purchase of power) and further agree as to which company and on what date such action shall be taken to increase the pool reserve.

Operating Committee

The Operating Committee will be fully authorized to determine and agree upon the following:

a. All matters pertaining to the coordination of maintenance of generating and transmission facilities of the companies.

b. All matters bearing upon the satisfactory synchronous operation of the systems of the companies.

c. Such matters not specifically provided in the KIP Agreement necessary for the coordination of the systems to the end that the potential savings will be realized to the fullest practicable extent.

6. *Practices Expected for the Planning and Development of Facilities*

a. *Coordinated load projections*

Each company to supply the Planning Committee with a 5-year load forecast every 6 months. The first 36 months of these forecasted demands are to be considered firm and not subject to revision and are to be used to determine billing and reserve quantities.

b. *Coordinated planning for reserves*

It is the objective of the companies to collectively provide an actual pool reserve of not less than 12% for any month during the term of the Indiana Pooling Agreement. With anticipated larger unit sizes present plans envision actual future reserves to be between 15% and 22%. ECAR criteria will also be considered.

c. *Coordinated system stability studies*

The Planning Committee will conduct any studies necessary to determine the security of the pool considering the additional transmission and generation facilities. ECAR criteria will be considered.

d. *Joint or staggered participation in facilities development*

Capacity normally is expected to be installed and owned by the individual companies; however, the KIP Agreement is expected to provide for joint ownership should it be recommended by the Planning Committee. As explained in item a. of section 7, surplus reserves are shared by the pool members.

7. *Operating Practices*

a. *Exchanges of capacity and energy*

The Pooling Agreement is expected to require that the reserves of the individual companies be equal and provide that a company having surplus capacity shall sell to a deficient company. The reserves are based on the highest system demands in the winter and summer 6-month periods. Energy may or may not be exchanged up to the extent of the capacity required for equalizing reserves.

The KIP Agreement is also expected to provide for interchange of power to equalize remaining available reserves on a day-to-day basis when one or more of the companies experience outages of generating units or are otherwise short of available operating reserves.

The KIP Agreement is expected to provide for several classifications of power exchanges including emergency, economy, surplus and short term.

b. *Coordination of reserves, including spinning reserve*

Coordination of installed and currently available reserves has been explained in a. above. Spinning reserve is provided by each company based on its own load situation.

c. *Coordination of maintenance*

As explained previously, long-range maintenance forecasts are to be exchanged by the companies. The KIP Agreement will provide for capacity and energy exchange to accomplish maintenance programs by equalizing currently available reserves.

d. *Economic dispatch*

Each company dispatches its system on an economic basis. Economy capacity and energy

exchanges realize further economies in system operation. Both Public Service Indiana and Kentucky Utilities Company have installed Westinghouse Prodac 510 digital economic dispatch systems and Indianapolis Power & Light Company has an L & N Analog control system for economic dispatch.

General

The Kentucky-Indiana Pool has many interconnections with surrounding systems. The Indianapolis Power & Light Company has an interconnection agreement with Indiana & Michigan Electric Company and Public Service Indiana has interconnection agreements with Northern Indiana Public Service Company, Indiana & Michigan Electric Company, Cincinnati Gas and Electric Company, Louisville Gas and Electric Company, Central Illinois Public Service Company, and Southern Indiana Gas and Electric Company. Kentucky Utilities Company has interconnection agreements with Ohio Power and Kentucky Power Companies, Appalachian Power Company, Central Illinois Public Service Company, Louisville Gas & Electric Company, Ohio Valley Electric Corporation, Indiana-Kentucky Electric Corporation, Electric Energy Incorporated, Tennessee Valley Authority, East Kentucky Rural Electric Cooperative Corporation and the City of Owensboro, Kentucky. These agreements provide arrangements for the interchange of power and energy covering one or more of the following classifications of transfer: emergency, economy, maintenance and short term. Many operating economies are effected through these agreements.

All KIP members are part of the group participating in the East Central Area Reliability Coordination Agreement in which plans for facilities and for operation of such facilities must meet certain minimum criteria.

The Indiana Pool is a liaison member of the Mid-America Inter-Pool Network regional planning organization and individuals from the Indiana Pool regularly attend meetings of the planning and operating working groups.

Section F—Coordinated Planning and Development, Kentucky, Illinois, Indiana Cooperatives (KII Pool)

1. *Type of organization*

   a. Planning and Operating Pool composed of Big Rivers R.E.C.C., Henderson, Ky., William W. Rumans, Manager; Hoosier Energy Division, Bloomington, Ind., Frank Ratts, Manager; Southern Illinois Power Cooperative, Marion, Ill., Tom Clevenger, Manager.

2. *History of Development*

Southern Illinois Power Cooperative commenced operation as an isolated electric utility in Southern Illinois in 1961. Southern Illinois Power Cooperative serves three REA financed distribution cooperatives in the southern part of Illinois.

Big Rivers R.E.C.C. commenced operation on January 1, 1966, serving three REA financed distribution type cooperatives in 14 counties in Western Kentucky. Big Rivers has an interconnection contract with the Southeastern Power Administration interconnecting at the Corps of Engineers 161 kV bus at Barkley Dam.

Hoosier Energy Division of the Indiana Statewide Rural Electric Inc., expects to commence operations on November 1, 1968 (since delayed by litigation) serving REA financed distribution cooperatives in central and southern Indiana.

In 1965 the three wholesale generating and transmitting cooperatives formed a planning and operating pool that commenced operation on July 1, 1967 when a 69 kV interconnection between Southern Illinois Power Cooperative and Big Rivers was completed.

Interconnections at 161-kV levels are planned by the Big Rivers R.E.C.C. and Hoosier Energy Division in 1968. A 161-kV interconnection between Southern Illinois Power Cooperative and Big Rivers will be made during 1969.

Southern Illinois Power Cooperative and Hoosier Energy have made contracts with SEPA utilizing the transmission facilities of Big Rivers R.E.C.C.

3. *List of Members*

The members of the Planning and Operating Pool are:

> Big Rivers R.E.C.C., 201 Third Street, Henderson, Ky.; Southern Illinois Power Cooperative, Box 689, Marion, Ill.; Hoosier Energy Division, 403–C S. Washington St., Bloomington, Ind.

4. *Requirements for Participation*

No finite rules for membership have been set forth by the three members. Other electric utilities desiring to participate in the pool operation under pool agreement would be eligible for admission upon application to either of the three pool members.

Henderson Municipal Power and Light, Henderson, Kentucky, has requested admission as a member commencing upon the completion of their new power plant in 1968.

5. *Organizational Structure*

The interconnection agreement provides for an operating committee consisting of one representative and one alternating representative from each member. The duties of the operation committee include the following.

The Operating Committee shall consist of one representative and an alternate representative of each party. Each representative and alternate shall be designated in writing delivered by each party to the other and shall be a responsible person connected with day-to-day operations of the respective party. The duties of the Operating Committee shall include the following:

(a) Determine generating capacity of each party.
(b) Determine spinning reserve requirements of each party.
(c) Determine capacity kilowatt losses for each party.
(d) Determine coincident interconnected system's annual maximum demand.
(e) Determine each party's annual maximum demand.
(f) Determine schedule of interim power for each party.
(g) Determine mutually agreeable points of delivery.
(h) Determine fuel costs, maintenance costs, and costs of placing units and plants into operation.
(i) Determine transmission line compensation.
(j) Determine interconnection facilities required.
(k) Schedule maintenance of generating units and major transmission facilities.
(l) Such other duties as may be mutually agreed to by the parties. If the Operating Committee is unable to agree unanimously on any matter coming under its jurisdiction, such matters shall be referred to the respective managements of the parties for decision. The Operating Committee shall meet as often as may be mutually agreed upon and at such times and places as may be agreed upon. Each party shall pay its own committee expense. Costs for joint planning studies or other costs shall be shared as mutually agreed by the parties.

6. *Practices in the Planning and Development of Facilities*

a. *Coordinated load predictions*

Each member makes estimated load requirement and at the present time these estimates are correlated into a pool requirement by Big Rivers R.E.C.C.

b. *Coordinated planning for reserves*

All reserves required by the integrated system is determined by meetings of the operating committee.

c. *Coordinated system stability studies*

The operating committee has employed consulting engineers to prepare stability studies.

d. *Joint facilities development*

The operating committee determines all requirements for the integrated system at the 161-kV transmission level and all generating requirements.

7. *Operating Practices*

The pool has not started actual operation. Limited operations will begin July 1, 1967.

Central dispatching will be established for the pool and is expected to be in operation by 1969. In the interim, dispatching will be coordinated between the members by system operators.

The interconnection agreement provides for exchange of interim power, emergency power, economy energy, coordination of system reserves, coordination of spinning reserves, mutual use of transmission facilities, and mutual assistance during emergencies.

Section G—Coordinated Planning and Development—Michigan Pool

1. *Type of Organization*

Planning and Operating Pool.

2. *History of Development*

The first 138-kV interconnection was installed in 1928 between Consumers Power's Blackstone Substation near Jackson and Detroit Edison's Superior Substation near Ypsilanti. This interconnection was used for the exchange of surplus energy and the transfer of energy during emergencies upon the system of either party.

In January 1949, Consumers and Edison executed a Power Interchange Agreement, effective as of January 1, 1949, by which the Blackstone-Superior line was to be increased in capacity. Provision was also made for the construction of a second high-voltage interconnection between Consumers' Hemphill Substation near Flint and Edison's system near Hunter's Creek. In addition to provision for mutual assistance during emergencies, the parties agreed to effect the maximum practicable economy in providing the electric power requirements of each system by coordination of their power supply programs, the sharing of reserve capacities, and by coordinated parallel operation of their respective systems to take mutual advantage of any economies in generation as well as any diversity between system loads. In 1952, a third high-voltage tie line was constructed between the two systems, extending from Consumers' J. R. Whiting generating plant to Edison's Monroe Substation at Monroe.

In December 1962, Consumers and Edison entered into an Electric Power Pooling Agreement, effective at once, which provides for pooled operations, coordination of planning and construction of electric generating and transmitting additions, the rendering of mutual assistance during emergencies, and the effecting of maximum economy in providing the electrical requirements of each system. From the inception of the agreement, the parties have engaged in continuous interchange of energy on an economy basis and have practiced joint planning of system development and operation. Six Pool units, one new 138-kV interconnection and nine new 345-kV interconnections, have been authorized and are presently under construction. In addition, a large pumped hydro project of 1,872 MW has been authorized under a joint ownership agreement.

3. *List of Members*

   a. Consumers Power Company

   b. The Detroit Edison Company

4. *Requirements for Participation*

By mutual agreement of Consumers and Edison, a third party may enter into these pooling arrangements.

5. *Organizational Structure Including Official Positions, Any Committees and their Functions, and Methods of Arriving at Decisions Affecting Members of the Coordinating Group.*

Five committees have been established to carry out the pooling objectives; an Administrative Committee, a Planning Committee, and Operating Committee, a Fiscal Committee and a Public Information Committee.

The responsibilities of the Administrative Committee include:

a. Consideration of any matters in connection with the administration of the Agreement such as interpretation of the Agreement, possible amendments or alterations thereto, supplementary agreements desirable or necessary in carrying out the objectives of the Agreement and related matters not specifically covered by the Agreement.

b. Making recommendations to the respective parties' managements regarding authorization of expenditures for facilities.

c. General supervision over, and the coordination of, the Planning, Operating, Fiscal and Public Information Committees.

The duties of the Planning Committee include:

a. Correlation of forecasts of loads and capability requirements.

b. Development of and making recommendations respecting optimum expansion plans and required written Agreements.

c. Development of and making recommendations respecting methods to share the savings from coordinated planning and operation of the parties' systems.

d. Development and completion of stability and load flow studies for assured dependability and security of bulk power supply.

e. Consideration of such other engineering matters as may, from time to time, arise in carrying out the objectives of the Agreement or as may be referred to it by the Administrative Committee.

The duties of the Operating Committee include:

a. All matters related to the day-to-day operation of the pool for lowest overall cost consistent with security of bulk power supply.
b. Development of procedures for and implementation of power exchanges between the Pool and other pools.
c. Coordination of maintenance of generating units and transmission lines.
d. Derivation, supplementation and implementation of Pool operating practices.
e. Determination and making of recommendations respecting net demonstrated capability for all owned generation, making recommendations whether or not to include nonutility party capacity in forecasted pool capability, and if included, to recommend ratings therefore, making recommendations respecting periodical testing procedures to determine common capacity rating methods, determination of the availability of generation facilities and their status if on cold standby, and making recommendations respecting the timing and rating for any change in capacity of either party's generation facilities.
f. Calculation of capacity and energy charges required between the parties hereto, and between a party or the parties hereto and other entities.
g. Consideration of such other operation matters as may, from time to time, arise in carrying out the objectives of the Agreement or as may be referred to it by the Administrative Committee.

The duties of the Fiscal Committee include:

a. Development of appropriate elements, methods of calculation, and values for capacity charges.
b. Making recommendations respecting appropriate payments between the parties to equalize annual costs for lines and other facilities which interconnect the parties' systems.
c. Development of capitalization bases to be utilized in accordance with the terms of the Agreement.
d. Maintenance of appropriate financial records as requested by the Administrative Committee.
e. Advising the Administrative Committee promptly of any change or revision of plant accounting or fiscal procedures of either party as effects the Agreement.
f. Consideration of such other fiscal or plant accounting matters as may, from time to time, arise in carrying out the objectives of the Agreement or as may be re-referred to it by the Administrative Committee.

The duties of the Public Information Committee include:

a. Development of principles and policies regarding the dissemination of public information on any phase of pooling activity.
b. The preparation and release of all public announcements and information to newspapers, radio, television and others news media that pertain to (i) major planning developments of the Pool, and (ii) major developments and events in the operation of the Pool.

General

All decisions respecting expenditures for generation as regards Pool units, expenditures for transmission as regards Pool units and expenditures for Pool interconnections are mutually agreed upon by the managements of both the Detroit Edison Company and Consumers Power Company.

6. *Practices in the Planning and Development of Facilities*

a. *Coordinated load projections*

Each company develops individually its own load projections for the existing year and future years, up to and including 20-year projections for economic studies. The combined load estimates of both companies are completely coordinated in the planning of all generation and transmission facilities.

b. *Coordinated planning for reserves*

The reserve requirement for the Pool is developed jointly. This includes the projection of loads, maintenance requirements and estimated forced outage requirements. The forced outage requirements are determined by probability studies. The reserve to be credited because of interconnections with parties outside the State of Michigan are jointly studied and agreed upon by the Pool. These reserves are shared equally. The allowance for load forecast error and regulation is mutually determined by the Pool.

c. *Coordinated system stability studies*

Comprehensive system stability and load flow studies are conducted for all years. They include studies for the present year, studies for future years with the addition of Pool units

and studies with future years as new interconnections are developed outside the State of Michigan. These studies are run for selected contingencies and include disaster cases such as loss of an entire generating plant.

d. *Joint or staggered participation in facilities development*

All Pool generating units are participated in jointly. The capacity is shared on an equalization of reserve basis throughout the period when the unit is a Pool unit. Normally, this sharing continues until the next Pool unit is installed. At that time, the previous unit reverts to the owning party and purchases and equalization of reserves are accomplished on the new Pool unit. Sharing of transmission associated with Pool units is accomplished in the same manner. Fixed, operating and maintenance costs of interconnection transmission facilities are shared equally by the parties. These practices result in planning and participation on a completely coordinated basis.

7. *Operating Practices*

a. *Exchanges of capacity and energy*

Firm purchases of capacity and energy from Pool units and, in special cases, from non-pool units, are provided for and accomplished. Prior to the installation of the first Pool unit, Detroit Edison had a firm purchase of capacity and energy from Consumers Power's Weadock No. 7 unit for a period of two years. Present signed agreements provide for sharing of the following Pool Units that are now in service or authorized:

Consumers Power—Campbell 2	1967
Detroit Edison—Trenton Channel 9	1967
Detroit Edison—St. Clair 7	1968
Consumers Power—Palisades 1	1970
Detroit Edison—Monroe 1	1970
Detroit Edison—Monroe 2	1971
Joint—Ludington 1–6	1973

For emergency conditions, all reserve in the entire Pool is available to the party that is meeting the emergency.

All energy delivered over the interconnection between the parties (other than specific purchases out of specific units) is considered as free flowing with all cost accounting done on a split-the-savings basis.

b. *Coordination of reserve including spinning reserve*

As stated in 6 above, the planned reserve for the Pool is completely coordinated. Spinning reserve in the day-to-day operation is completely coordinated with each party responsible for providing its proportion of the total requirement based on relative loads each hour. Provision is made, and in practice occurs, for the hour-by-hour purchase and sale of spinning reserve on economic, system and sub-area reliability bases.

c. *Coordination of maintenance*

Maintenance is completely coordinated by the Operating Committee. Yearly maintenance schedules are jointly prepared and day-to-day maintenance is also coordinated and accomplished.

d. *Economic dispatch including description of control facilities*

All units in the State of Michigan are dispatched on a common basis for the lowest cost in the Pool after assuring area reliability. Presently, Detroit Edison dispatches by an on-line computer with Consumers Power's dispatchers utilizing output from Computer analyses on a manual basis. By early 1969 all Consumers Power and Detroit Edison generating units will be dispatched from a central dispatch center manned by personnel from both companies.

Other Agreements

a. *Consumers Power Company-City of Lansing Interconnection Agreement*

In 1941 a 46 kV interconnection was installed between Consumers Power Company and the City of Lansing for the transfer of energy during emergencies. In 1964 Consumers Power and the City of Lansing executed a new agreement effective immediately. The interconnection was strengthened and uprated at that time. The new agreement provides for emergency assistance up to the limit of the interconnection.

A Planning Committee was established and its duties include:

(1) Exchange of data on load forecast and planned generation capabilities for a period at all times extending four years into the future.

(2) Consideration of any engineering matters that may arise in connection with the agreement.

An Operating Committee was established and its duties include:

(1) All matters related to the day-to-day operation of the interconnections between the two parties.

(2) All matters relating to operating conditions during emergency situations.

Load, capability and reserve data are interchanged and utilized by the Planning Committee. Stability studies have been conducted and day-to-day maintenance coordination and spinning reserve coordination are accomplished as required. No economic dispatch between the parties is accomplished at this time.

b. *Consumers Power Company-City of Holland Agreement*

A 46–kV interconnection was made in 1955 between Consumers Power Company and the City of Holland along with a contract for electric service. A new agreement was executed in 1967 that provides for the interchange of capacity and energy and establishes an Operating Committee and a Planning Committee.

c. *The Detroit Edison Company-City of Wyandotte*

In 1964 Detroit Edison and the City of Wyandotte executed a new interchange agreement and authorized a new interconnection to be completed early in 1966. The contract provides for:

(1) Rendering mutual assistance during emergencies, and

(2) Effecting the maximum economy practical within the limits of satisfactory operating conditions as determined by each party in providing the electric power requirements of each utility.

A Policy Committee was created to be responsible for carrying out the general provisions and intent of the agreement and to supervise the Scheduling Committee.

A Scheduling Committee was created to:

(1) Handle all matters pertaining to the day-to-day scheduling of energy.

(2) To determine rates and charges under various conditions of interchange.

(3) To be responsible for all matters pertaining to the coordination of maintenance.

(4) To perform any other matters as may be delegated it by the Policy Committee.

The contract provides for maintenance coordination, provision for firm capacity purchase and sale and economy energy exchange.

d. *The Detroit Edison Company-City of Detroit*

Interconnections between The Detroit Edison Company and the City of Detroit were made in 1931, with the contract revised in 1939. The contract provides for the transfer of energy during emergencies.

e. *Other Agreements*

Consumers Power-Detroit Edison-Ontario Hydro.

Section H—Coordinated Planning and Development—Michigan-Ontario

1. *Type of Organization*

Planning and Operating Agreement.

2. *History of Development*

a. The first interconnections were installed in 1953 between Detroit Edison and Ontario Hydro. Consumers Power was not a party at that time to the agreement. Two 120-kV interconnections were installed, one between Edison's Marysville Plant and Ontario Hydro's Sarnia Substation and one between Edison's Waterman Substation and Ontario Hydro's Keith Plant. These interconnections were used for the exchange of surplus and the transfer of energy during emergencies on the system of either party. The agreement had provisions also for coordinating maintenance and for purchase and sale of spinning reserve. The agreement provided for an Administrative Committee and a Scheduling Committee to handle all facets of the Interconnection agreement and actual operation.

b. In February 1966, Consumers Power, Detroit Edison and Ontario Hydro executed a

new interconnection agreement effective immediately. A third high-voltage interconnection between Edison's St. Clair Plant and Ontario's new Lambton Plant was provided for with construction to be completed by December 1966. The new interconnection was to be operated initially at 120-kV with transformation to 345-kV scheduled in 1968. The new agreement provides for emergency assistance, exchange of surplus energy, the emergency exchange of kilovars and spinning reserve, coordinated maintenance and provision for coordinated development to the extent mutually deemed desirable.

c. A new agreement is being prepared which will make provision for several additional coordination measures. These include Annual Diversity, Coordinated Maintenance, Short Term Power, Security Energy and System Optimization Services.

3. *List of Members*

a. Consumers Power Company.

b. The Detroit Edison Company.

c. The Hydro-Electric Power Commission of Ontario.

4. *Requirements for Participation*

Limited to the three parties listed in 3 above.

5. *Organizational Structure Including Official Positions, any Committees and their Functions, and Methods of Arriving at Decisions Affecting Members of the Coordinating Group*

Three committees have been established to carry out the interconnection objectives; an Administrative Committee, a Planning Committee and an Operating Committee.

a. The responsibilities of the Administrative Committee include:

(1) Consideration of any matters in connection with the administration of the agreement such as interpretation of the agreement, possible amendments or alterations thereto, supplementary agreements desirable or necessary in carrying out the objectives of the agreement and related matters not specifically covered by the agreement.

(2) Making recommendations to the respective parties' managements regarding authorization of expenditures for facilities.

(3) General supervision over, and the coordination of, the Planning and Operating Committees.

b. The duties of the Planning Committee include:

(1) Correlation of forecast of load and capability requirements.

(2) Performance of the necessary engineering studies to determine the adequacy of existing interconnections.

(3) Performance of the necessary engineering and economic studies on increasing the total interconnection capability.

(4) Performance of the necessary engineering and economic studies relating to proposals for coordinated development of facilities.

(5) Report and recommend to the administrative committee on the agreements and facilities required and on the sharing of costs and benefits.

(6) Consideration of such other engineering matters as may arise in carrying out the objectives of the agreement or as may be referred to it by the Administrative Committee.

c. The duties of the Operating Committee include:

(1) All matters related to the operation of the parties' systems including purchases and sales of capacity, energy, spinning reserve and the like.

(2) Calculations monthly of capacity and energy charges.

(3) Coordination of maintenance.

(4) Consideration of such other operating matters as may arise in carrying out the objectives of the agreement or as may be referred to it by the Administrative Committee.

General

All decisions respecting expenditures as regards strengthening of present interconnections or construction of new interconnections are mutually agreed upon by the managements of the three parties.

6. *Practices in the Planning and Development of Facilities*

a. *Coordinated load projections*

Each company develops individually its own load projections for the existing year and

future years up to and including 20-year projections for economic studies. The combined load estimates are utilized in all planning studies.

b. *Coordinated planning for reserve*

The reserve requirement for Michigan is developed jointly by Consumers Power and Detroit Edison. This includes the projection of loads, maintenance requirements and estimated forced outage requirements. The reserves to be credited because of interconnections with parties outside the State of Michigan are studied and agreed upon by Consumers Power and Detroit Edison and are shared equally between the two.

The reserve requirement for Ontario is developed by Ontario Hydro. Both Michigan and Ontario utilize all reserve data in the development of their planning.

c. *Coordinated system stability studies*

Comprehensive system stability and load flow studies are conducted for all years. They include studies for the present year, studies for future years with the addition of authorized interconnection development and for later years with expected future interconnections. These studies are run for selected contingencies and include disaster cases such as loss of an entire generating plant.

d. *Joint or staggered participation in facilities development*

The agreement provides for coordinated development to the extent mutually deemed desirable to achieve possible economies and increase security of the bulk power supply. To date, no agreements on participation in generating units on a staggered construction basis have been consummated.

7. *Operating Practices*

a. *Exchanges of capacity and energy*

Purchases of emergency capacity and energy are provided for and accomplished. Purchases of surplus and economy energy are provided for and accomplished. All economy energy is handled by cost accounting on a split-the-savings basis.

b. *Coordination of reserve including spinning reserve*

As stated in Item 6 above, the planned reserve for the parties is coordinated by the Planning Committee. Spinning reserve in the day-to-day operation is completely coordinated with Michigan and Ontario providing their own total requirements, respectively. Provision is made and in practice occurs for the hour-by-hour purchase and sale of spinning reserve on economic, system and subarea reliability bases.

c. *Coordination of maintenance*

Maintenance is coordinated by the Operating Committee to assure maximum reliability of the systems. In addition, yearly maintenance schedules are reviewed by the Planning Committee in the development of the economic engineering plans.

d. *Economic dispatch including description of control facilities*

All units in the State of Michigan are dispatched on a common basis for the lowest cost in the Michigan Pool after assuring area reliability. All units in Ontario are dispatched on a common basis by Ontario. Presently, the economy dispatch between Michigan and Ontario is handled by the Detroit Edison dispatchers and the Ontario Hydro dispatchers utilizing computer data. It is planned that the entire Michigan Pool will be dispatched in 1969 from a central dispatch center with communication and control facilities with Ontario included.

Section I—Coordinated Planning and Development
"MIIO" GROUP (Michigan-Indiana-Illinois-Ohio)

1. *Type of Organization*

Planning and Operating Agreement.

2. *History of Development*

Starting in 1963, representatives of the Michigan Pool (Consumers Power Company-The Detroit Edison Company), American Electric Power, Commonwealth Edison Company, Northern Indiana Public Service Company and The Toledo Edison Company formed a planning group to investigate the technical and economic feasibilities of EHV interconnections between Michigan and Indiana and between Michigan and Ohio. This group also developed preliminary contractual agreements for consideration of each party's management. In March 1966 interconnection agreements between the above parties were signed by the managements of the parties. Two 345,000 volt double circuit interconnections are to be constructed and be in service in 1969. Michigan terminals of one of these double-circuit lines will be at Detroit Edison's Wayne Substation with the lines proceeding south through Consumers Power territory with one southern termination at Toledo Edison's Lemoyne Substation and the other termination at AEP's Fostoria Central Substation. The other 345,000 volt double-circuit interconnection is to terminate at Consumers Power's Palisades Substation and the lines proceed southward to AEP's Olive and Twin Branch Substation.

3. *List of Members*

   a. Consumers Power Company.
   b. The Detroit Edison Company.
   c. Northern Indiana Public Service Company.
   d. Commonwealth Edison Company.
   e. American Electric Power.
   f. The Toledo Edison Company.

4. *Requirements for Participation*

Limited to the six parties as listed in 3 above.

5. *Organizational Structure including Official Positions, any Committees and their Functions, and Methods of Arriving at Decisions Affecting Members of the Coordinating Group*

Two committees have been established to carry out the objectives of the parties under the MIIO Agreement. A Planning Committee and an Operating Committee.

a. The responsibilities of the Planning Committee include:

   (1) Initiating studies and investigations leading to mutually agreed upon recommendations to the parties concerning adequacy of interconnection facilities, staggering of construction and adequacy of generating reserves, both individually and collectively.
   (2) Keeping abreast of all advances in engineering technology in fields allied to its responsibilities and recommending the development and adoption of new methods and possible modifications of the interconnection agreements.
   (3) The conducting of engineering studies to determine the feasibility of increasing or affirming the effective amount of emergency interconnection assistance available.

b. The duties of the Operating Committee include:

   (1) The coordination of the operation of each party's respective facilities in order to carry out the terms of the agreements.
   (2) All matters pertaining to the coordination of maintenance of the generating and transmission facilities of the parties.
   (3) All matters pertaining to the control of time, frequency, energy flow, kilovar exchange, power factor, voltage, and other similar matters bearing upon the satisfactory synchronous operation of the systems of the parties.
   (4) Such other matters not specifically provided for in the agreements upon which cooperation, coordination and agreement as to quantity, time, method, terms and conditions are necessary in order that the operation of the systems of the parties may be coordinated to the end that the potential savings in operating costs will be realized to the fullest practical extent.

General

All decisions respecting expenditures for interconnection facilities are mutually agreed upon by the managements of the parties.

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6. *Practices in the Planning and Development of Facilities*

   a. *Coordinated load projections*

   Each party develops individually its own load projections for the existing year and future years up to and including 20-year projections for economic studies. The combined loads are utilized by the Planning Committee in all their engineering and economic studies.

   b. *Coordinated planning for reserves*

   The reserve requirement for each party is developed individually by each party. However, the year-by-year planned reserves of the entire group are reviewed by the Planning Committee to determine the adequacy or inadequacy of reserve generating capacity and transmission facilities being provided. If it should be found that one party is placing a burden upon the other, the party causing such burden shall take such measures as are necessary to remove the burden from the other parties or the parties shall enter into such arrangements as shall provide for equitable compensation.

   Probability analyses of each party's generating units are conducted with further probability studies meshing the entire group performed to determine on a probability basis the reserve required for a given planning criteria.

   c. *Coordinated system stability studies*

   Comprehensive system stability and load flow studies are conducted for all years beginning with the in-service date of the interconnections. They include studies for that year and studies for future years with the addition of new generating units and new interconnections. These studies are run for selected contingencies and include disaster cases such as loss of an entire generating plant.

   d. *Joint or staggered participation in facilities development*

   The interconnections are participated in jointly. The contracts have provision for staggering of construction of generating facilities and will be implemented throughout the years.

7. *Operating Practices*

   a. *Exchanges of capacity and energy*

   The agreements have provisions for firm purchases and sales of capacity and energy from specific units or from a system for a long-term purchase. The contracts also have provision for capacity and energy transactions on a short-term basis, i.e., weekly. For emergency conditions all reserve in the entire pool is available to the party that is meeting the emergency. The contracts have provision for exchange of energy for maintenance coordination and for exchange of energy on an economic basis with such costs being made on a split-the-savings basis. Provisions for seasonal diversity exchanges are also included.

   b. *Coordination of reserve including spinning reserve*

   As stated in Item 6 above, the planned reserve for the Group is coordinated by the Planning Committee. At the time the interconnections are in service there will be complete coordination of spinning reserve.

   c. *Coordination of Maintenance*

   At the time the interconnections are in service the day-to-day maintenance is planned to be coordinated to assure maximum reliability of the systems. Maintenance coordination is presently being utilized for planning purposes by the Planning Committee.

   d. *Economic dispatch including description of control facilities*

   Michigan, which includes Consumers Power and Detroit Edison, will operate at the time these interconnections are in service from a Joint Dispatch Center which will be completely coordinated with the other parties' dispatch centers.

Section J—Coordinated Planning and Development, East Kentucky RECC and Kentucky Utilities Company

1. *Organization*

   a. *Reporting Organization*

   East Kentucky Rural Electric Cooperative Corporation [1]
   Post Office Box 555
   Winchester, Kentucky

   b. *Type of Organization (East Kentucky RECC)*

   Rural electric generation and transmission cooperative, operating in a pooling arrangement with Kentucky Utilities Company and having interconnection with T.V.A., Kentucky Power Company, and Union Light, Heat, and Power Company.

2. *History of Development* (East Kentucky RECC)

Operation began in 1954 with the completion of a generating station at Ford, Kentucky. At this time East Kentucky had interconnection agreements with Kentucky Utilities Company, T.V.A., Union Light, Heat and Power Company.

In 1964, a new power plant was completed at Burnside, Kentucky, along with an interconnection agreement with Kentucky Power Company.

East Kentucky has 18 distribution cooperative members and has transmission facilities in 90 counties in Kentucky.

3. *List of Members*

The members of the operating pool are East Kentucky and Kentucky Utilities Company.

4. *Requirements for Participation*

   a. *Pool Participation*

   To have contractual agreements.

5. *Organizational Structure*

Two committees, administrative and operating, appointed by the respective managements make recommendations to them concerning system coordinated construction and operation consistent with guidelines as set out in the interconnection agreement.

   a. *Administrative Committee*

   1. Recommends coordinated plans for generation, transmission, communication, control, etc.
   2. Establish operating and maintenance procedures.
   3. Recommends reserve requirements of the pool.
   4. Review interconnections with other systems.
   5. Establish policies and practices for the guidance of the operating Committee.

   b. *Operating Committee*

   Establish operating and maintenance schedules, control and operating procedures and interchange accounting procedures. Make available to the Administrative Committee operating information, both with internal and with other systems.

6. *Planning and Development* (Pool Operation Practices)

   a. *Coordinated Load Provisions*

   The Administrative Committee determines estimated load growth and recommends to respective management, according to contract requirements, the estimated in-service date of additional generation.

   b. *Coordinated Plan for Reserves*

   The Administrative Committee agrees on estimated loads of combined system and recommends to management appropriate reserve requirements.

   c. *Coordinated System Stability Studies*

   A function of the Administrative Committee.

   d. *Joint Facilities Development*

   Present contractual agreements have the following provisions:

   East Kentucky RECC to install, when necessary (presently planned for early 1969), a 200 megawatt generator in the Cooper Station. Kentucky Utilities Company to install

[1] The following is a list of participating member cooperatives:

Big Sandy RECC	Inter-County RECC
Blue Grass RECC	Jackson County RECC
Clark RECC	Licking Valley RECC
Cumberland Valley RECC	Nolin RECC
Farmers RECC	Owen County RECC
Fleming-Mason RECC	Salt River RECC
Fox Creek RECC	Shelby RECC
Grayson RECC	South Kentucky RECC
Harrison County RECC	Taylor County RECC

427 megawatts of capacity at the E. W. Brown generating station. The contract also provides for coordination of transmission and other facility installations. Contract expiration date to be January 31, 1974.

7. *Operating Practices*

a. *Exchange of Capacity and Energy*

Contractual arrangements provide for the purchase and sale of the following types:

Contract Power

1. Power and energy to comply with the reserve capacity requirements of a participant.
2. Power and energy necessary to supply a party's anticipated peak system load when said load shall exceed the net capability of its generating equipment, plus other purchases.

Economy Energy

The purchase and sale of energy can be made on an economic basis.

b. *Coordination of Reserves*

Present reserves require East Kentucky to maintain 15% above its peak system load, Kentucky Utilities to maintain 10% above its peak system load. Spinning reserve is recommended by the interconnected group and agreed to by the Administrative Committee. Each party's share of spinning reserve is agreed upon by the Operating Committee.

c. *Coordination of Maintenance*

Generator maintenance is determined by the Administrative Committee. Transmission and other maintenance is scheduled through the Operating Committee and the system dispatcher of Kentucky Utilities Company. All transmission system emergencies and planned switching orders are under the control of the Kentucky Utilities joint system dispatcher.

d. *Economic Dispatch*

East Kentucky generates on a pre-determined schedule, equal to its hour-by-hour estimated requirements dividing generation between Dale Station and Cooper Station on the most economic schedule. Kentucky Utilities does not include East Kentucky generation as part of its present economic dispatch system. Area load control is maintained by Kentucky Utilities dispatcher on frequency bias for the pool operation. East Kentucky transactions, with external interconnections, are deemed to take place at the point of interconnection with such other systems. Kentucky Utility maintains a swing generator.

e. *Emergency Stand-by*

East Kentucky and Kentucky Utilities have agreed contractually to supply to each other such power as it can without hazard to its property or operation.

East Kentucky and Kentucky Power shall supply to each other, in event of an emergency, a maximum of 25,000 kw, provided it does not impose a hazard to its other loads. Such delivery shall only be made for a 48-hour period and energy and power returned "in kind". East Kentucky and T.V.A. have the same basic relations as between East Kentucky and Kentucky Power Co. Maximum supply of 25,000 kw.

Section K—Coordinated Planning and Development—Other Kentucky Utilities

1. *Louisville Gas and Electric Company*

The Louisville Gas and Electric Company is not at present participating in a formal coordinating group as designated in the Federal Power Commission memorandum dated June 2, 1966.

The Louisville Gas and Electric Company operates as an individual company but maintains interconnections with all neighboring utilities. Interconnection agreements are now and have long been in effect with Cincinnati Gas and Electric Company, Public Service Indiana, Kentucky Utilities Company, Southern Indiana Gas and Electric Company, and Tennessee Valley Authority. All of the connections operate closed and are for the purpose of buying and selling capacity and interchanging economy and emergency power. Each of these agreements provides for operating committees who coordinate the operation and the exchange of information such as load forecasts, capacity data, maintenance schedules, and any other information which would be helpful in meeting our joint responsibilities.

The Louisville Gas and Electric Company is an active participant in the Ohio Valley Electric Company, being represented on the Board of Directors and the Operating Committees. The Company's electric transmission lines are directly tied with the OVEC system for the purchase and sale of energy. Transmission load flow studies are regularly made in cooperation with the other participants in the group.

The Louisville Gas and Electric Company has been, since its inception, an active participant in the Interconnected Systems Group, NAPSIC, and the Indiana Area Committee for Coordination of Power Supply.

2. *Kentucky Utilities Company*

Kentucky Utilities Company does not constitute a "coordinating group" nor is it presently a member of such a group in the context in which this term is used in the Federal Power Commission memorandum dated June 2, 1966. However, Kentucky Utilities Company does operate under various contracts with other systems which provide coordination of some activity. For example, an agreement between the company and East Kentucky RECC, dated August 7, 1963, as supplemented October 27, 1964, the provisions of which are carried out through administration and operating committees, provides for exchange of load forecasts and scheduling of certain generating equipment additions on the systems of the parties through 1974. This agreement also provides for limited coordination of transmission construction and operation by the parties.

Kentucky Utilities Company has entered into an interconnection agreement with Louisville Gas and Electric Company, dated July 22, 1966, which provides for the furnishing of mutual emergency service; the interchange, sale and purchase of economy energy, and the sale and purchase of short-term energy.

Kentucky Utilities Company has an interconnection agreement with Ohio Power Company, dated January 17, 1950, and supplemented by an agreement dated May 20, 1966, which provides for the purchase and sale of short-term power.

Kentucky Utilities Company has an interconnection agreement with the Tennessee Valley Authority, dated March 22, 1951, and supplemented from time to time since that date. This agreement provides for the delivery of power to area loads of the respective parties; the purchase and sale of economy energy and reciprocal emergency transactions.

Kentucky Utilities Company entered into a contract with the City of Owensboro, dated September 23, 1960, which provided for KU to purchase the capacity and energy from the City's Elmer Smith Generating Station in excess of that required by the City of Owensboro. KU provides the City of Owensboro with maintenance standby service for the Elmer Smith Generating Unit as well as emergency service.

KU entered into an agreement with the Ohio Valley Electric Corporation, dated July 10, 1953, in which it was agreed that KU would purchase surplus capacity from the generating facilities of the Corporation in excess of that required by the Atomic Energy Commission in an amount equivalent to the ratio of its power participation ratio to the surplus capacity available. KU agreed to supply OVEC supplemental power to the extent that such power would be required to meet the demands of AEC in the event that the OVEC generating facilities were not capable at any given time of fulfilling the AEC requirements.

Kentucky Utilities Company entered into a contract with Electric Energy, Inc., dated August 1, 1953, in which it agreed to purchase the surplus capacity from the Joppa plant of EEI which is not required in supplying the contractual requirements of the Atomic Energy Commission. KU is committed to purchase 20% of the available surplus capacity from EEI.

These two companies, Louisville Gas and Electric Company and Kentucky Utilities Company, with 23 other utilities, are actively participating in the implementation of the East Central Area Reliability Coordination Agreement (ECAR), designed further to augment reliability in the supply of bulk electric power in the multi-state region served by the ECAR members. ECAR and the companies are establishing principles and procedures with respect to the achievement of this goal, including, but not limited to, minimum installed capacity and spinning reserves to be provided by each company, the distribution of spinning reserves, coordination of generation and transmission maintenance, emergency measures, communication, protection, and the evaluation and simulated testing of systems performance.

APPENDIX VII–C

THE OHIO VALLEY ELECTRIC CORPORATION (OVEC)

The Ohio Valley Electric Corporation (OVEC), along with Indiana-Kentucky Electric Corporation (IKEC) its subsidiary, together demonstrate the high degree of coordination which has existed for some time among investor-owned utilities in a large part of the East-Central Region. This project involved fifteen electric utility companies of the region and was formed to supply energy to the Portsmouth Area Project of the Atomic Energy Commission located north of Portsmouth, Ohio.

This tremendous undertaking which has supplied some 17 billion kilowatt-hours per year and an initial contract demand of 1,800 kilowatts was created in 1952 in response to an inquiry of the Atomic Energy Commission regarding interest by the power industry in constructing such a facility. For its time this was a tremendous challenge to the power industry requiring approximately $400,000,000 of new capital and a construction schedule which was extremely tight. The investor-owned companies agreed to supply energy to the AEC prior to the completion of the generating facilities and, in fact, these companies did supply over 1,000,000 kilowatts in late 1955.

From its inception in January of 1952 and its incorporation in October of 1952, construction started in early 1955. Barely two years after groundbreaking, the first two of eleven generating units with a total capability of 2,350,000 kilowatts went "on the line." The whole project including negotiation for about 7½ million tons of coal a year, the design and construction of eleven generating units, and the design and construction and operation of a 345 kV transmission system—the highest voltage ever used in this country at that time—exemplified the coordination and cooperation that is possible in this region. OVEC has supplied in one year as much as 2,100,000 kilowatts of demand. Energy has been delivered since 1956 at a cost to the AEC which has averaged below 0.4¢ per kilowatt-hour. OVEC has also contributed taxes and as such makes its contiribution to the Nation's economy.

In recent years production at the AEC diffusion plant has been temporarily cut back, thus reducing its requirements for power. The sponsoring companies have purchased all of the power over and above AEC requirements and have provided transmission for the delivery of this energy to the interconnected sponsoring companies. As the AEC load again increases, it is expected that this cooperative endeavor will provide for the future requirements of the AEC in an economic and reliable manner.

APPENDIX VII–D

Yankee-Dixie Power, Inc., Membership Within the East Central Region

INDIANA

1.	Decatur County Rural Electric Membership Corporation	Greensburg.
2.	Shelby County Rural Electric Membership Corporation	Shelbyville.
3.	Southern Indiana Rural Electric Cooperative, Inc	Tell City.
4.	Southeastern Indiana Rural Electric Membership Corporation	Osgood.
5.	Dubois Rural Electric Cooperative, Inc	Jasper.
6.	Kosciusko County Rural Electric Membership Corporation	Warsaw.
7.	Boone County Rural Electric Membership Corporation	Lebanon.
8.	Marshall County Rural Electric Membership Corporation	Plymouth.
9.	Miami-Cass County Rural Electric Membership Corporation	Peru.
10.	Rush County Rural Electric Membership Corporation	Rushville.
11.	Kankakee Valley Rural Electric Membership Corporation	Wanatah.
12.	LaGrange County Rural Electric Membership Corporation	LaGrange.
13.	Harrison County Rural Electric Membership Corporation	Corydon.
14.	Jasper County Rural Electric Membership Corporation	Rensselaer.
15.	Morgan County Rural Electric Membership Corporation	Martinsville.
16.	Wabash Valley Power Association	Peru.
17.	White County Rural Electric Membership Corporation	Monticello.
18.	Fulton County Rural Electric Membership Corporation	Rochester.
19.	Jay County Rural Electric Membership Corporation	Portland.
20.	Stuben County Rural Electric Membership Corporation	Angola.
21.	Carroll County Rural Electric Membership Corporation	Delphi.
22.	Tipmont Rural Electric Membership Corporation	Linden.
23.	Hendricks County Rural Electric Membership Corporation	Danville.
24.	United Rural Electric Membership Corporation	Huntington.
25.	Bartholomew County Rural Electric Membership Corporation	Columbus.
26.	Daviess-Martin Rural Electric Membership Corporation	Washington.
27.	Whitley County Rural Electric Membership Corporation	Columbia City.
28.	Noble County Rural Electric Membership Corporation	Albian.
29.	Hancock County Rural Electric Membership Corporation	Greenfield.
30.	Orange County Rural Electric Membership Corporation	Orleans.
31.	Sullivan Rural Electric Membership Corporation	Sullivan.
32.	Crawfordsville Electric Light & Power	Crawfordsville.
33.	Clark County Rural Electric Membership Corporation	Sellersburg.
34.	The Hoosier Energy Division	Bloomington.

KENTUCKY

1.	Cumberland Valley Rural Electric Cooperative Corporation	Gray.
2.	East Kentucky Rural Electric Cooperative Corporation	Winchester.
3.	Fleming-Mason Rural Electric Cooperative Corporation	Flemingsburg.
4.	Fox Creek Rural Electric Cooperative Corporation	Lawrenceburg.

KENTUCKY—Continued

5. Grayson Rural Electric Cooperative Corporation	Grayson.
6. Harrison County Rural Electric Cooperative Corporation	Cynthiana.
7. Inter-County Rural Electric Cooperative Corporation	Danville.
8. Nolin Rural Electric Cooperative Corporation	Elizabethtown.
9. Shelby Rural Electric Cooperative Corporation	Shelbyville.
10. South Kentucky Rural Electric Cooperative Corporation	Somerset.
11. Municipal Light & Power System, City of Paris	Paris.
12. Vanceburg Electric Light, Heat & Power System	Vanceburg.
13. Farmers Rural Electric Cooperative Corporation	Glasgow.
14. Clark Rural Electric Cooperative Corporation	Winchester.
15. Jackson Purchase Rural Electric Cooperative Corporation	Paducah.
16. Jackson County Rural Electric Cooperative Corporation	McKee.
17. Big Rivers Rural Electric Cooperative Corporation	Henderson.
18. Owen County Rural Electric Cooperative Corporation	Owenton.
19. Warren Rural Electric Cooperative Corporation	Bowling Green.
20. Taylor County Rural Electric Cooperative Corporation	Campbellsville.
21. Berea College Electric Utility	Berea.
22. Blue Grass Rural Electric Cooperative Corporation	Nicholasville.
23. Salt River Rural Electric Cooperative Corporation	Bardstown.
24. Big Sandy Rural Electric Cooperative Corporation	Paintsville.
25. Glasgow Electric Plant Board	Glasgow.
26. Licking Valley Rural Electric Cooperative Corporation	West Liberty.
27. Electric & Water Plant Board	Frankfort.
28. Kentucky Municipal Electric Power	Owensboro.

OHIO

1. Division of Electricity, City of Columbus	Columbus.
2. Deshler Municipal Utilities	Deshler.
3. Lorain-Medina Rural Electric Cooperative	Wellington.
4. Orrville Municipal Utilities	Orrville.
5. City of Bowling Green, Ohio Municipal Utilities	Bowling Green.
6. Municipal Light & Water Works	Bryan.
7. Painesville Electric Power	Painesville.
8. Celina Municipal Utilities	Celina.

PENNSYLVANIA

1. Adams Electric Cooperative, Inc	Gettysburg.
2. Central Electric Cooperative, Inc	Parker.
3. Northwestern Rural Electric Cooperative Association, Inc	Cambridge Springs.
4. Pitcairn Municipal Light Plant	Pitcairn.
5. Somerset Rural Electric Cooperative, Inc	Somerset.
6. Borough of Ephrata	Ephrata.
7. Valley Rural Electric Cooperative, Inc	Huntington.
8. Claverack Electric Cooperative, Inc	Towanda.
9. Sullivan County Rural Electric Cooperative, Inc	Forksville.
10. Allegheny Electric Cooperative, Inc	Harrisburg.
11. United Electric Cooperative, Inc	Brookville.
12. Borough of Chambersburg	Chambersburg.

VIRGINIA

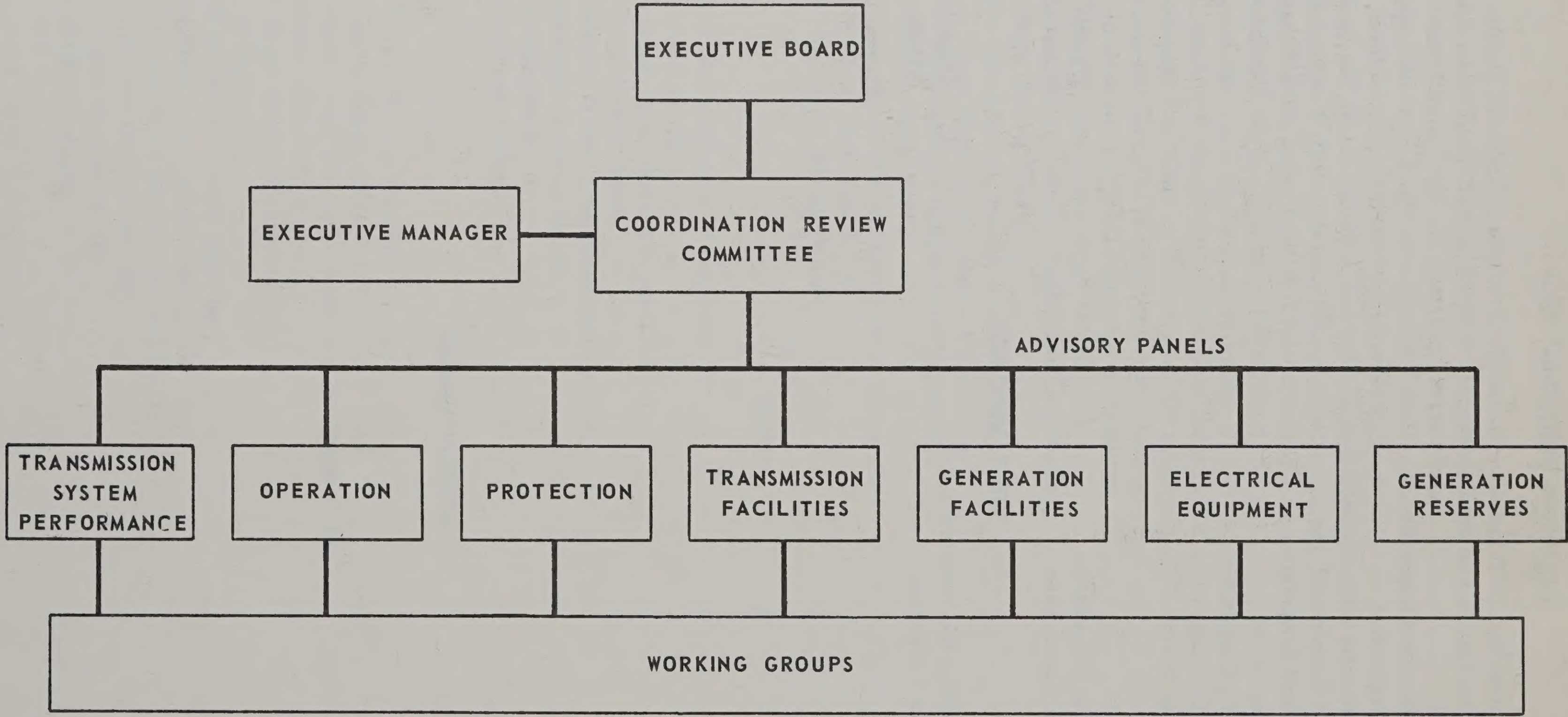
1.	Accomack-Northampton Electric Cooperative	Parksley.
2.	City of Danville Water, Gas & Electric Department	Danville.
3.	Town of Front Royal	Front Royal.
4.	Northern Piedmont Electric Cooperative	Culpepper.
5.	Southside Electric Cooperative	Crewe.
6.	Shenandoah Valley Electric Cooperative	Dayton.
7.	Mecklenburg Electric Cooperative, Inc	Chase City.
8.	Central Virginia Electric Cooperative	Lovingston.
9.	B-A-R-C Electric Cooperative	Millboro.
10.	Northern Neck Electric Cooperative	Warsaw.
11.	Community Electric Cooperative	Windsor.
12.	Virginia Electric Cooperative	Bowling Green.
13.	Town of Elkton, Inc	Elkton.
14.	Town of Salem	Salem.
15.	Old Dominion Electric Cooperative	Chase City.
16.	Harrisonburg Electric Commission	Harrisonburg.

WEST VIRGINIA

1.	Harrison Rural Electrification Association, Inc	Clarksburg.
2.	Preston Public Service Corporation	Masontown.

APPENDIX VIII-A

ECAR ORGANIZATION



APPENDIX VIII–B

ECAR DOCUMENT No. 1 [1]—RELIABILITY CRITERIA FOR EVALUATION AND SIMULATED TESTING OF THE ECAR BULK POWER SUPPLY SYSTEMS

The East Central Area Reliability Coordination Agreement provides for the establishment of principles and procedures regarding matters affecting the reliability of bulk power supply within ECAR. It recognizes that the evaluation and simulated testing of systems' performance are essential elements in assuring reliability. In accordance with the provisions of the Agreement, the ECAR members have formulated a set of reliability criteria to be used as the basis for such evaluation and simulated testing.

This document presents the reliability criteria adopted by ECAR for the above purposes. It represents the combined judgment of the ECAR members and includes, in addition to a listing of reliability criteria, a brief description of the underlying principles that served as the basis for their development.

Basis for the Selection of Reliability Criteria

In the process of formulating the reliability criteria presented in this document, the ECAR members recognized:

1. The need to plan, build, and operate bulk power supply systems that would be immune to uncontrolled, widespread, cascading power interruptions even under the most adverse credible conditions and the fact that it is technically feasible to achieve this objective.
2. The importance of providing a high degree of reliability for local power supply but the impossibility of providing 100% reliability to every customer or every local area.
3. The importance of considering local conditions and requirements in setting up criteria for the reliability of local power supply and the need, therefore, to view reliability in local areas as the responsibility of the individual ECAR members.

[1] October 1967.

In addition to the above, the ECAR members recognized the impossibility of anticipating, and testing for, all possible contingencies that could occur on either the present or future interconnected bulk power supply network of the ECAR systems. ECAR believes, therefore, that the reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies that can and that cannot be readily visualized, rather than comprise a detailed listing of probable disturbances. In view of this, the selection of reliability criteria is based not on whether the specific contingency for which the system is being tested is in itself probable or even possible, but rather on whether it constitutes an effective and practical means to stress the systems and thus to test their ability to avoid uncontrolled, area-wide power interruptions even under the most adverse credible conditions.

The ECAR members believe that the most effective safeguard against a possible occurrence of uncontrolled, area-wide power interruptions on a large bulk power supply system is strict adherence to the basic principles of bulk power supply planning, with full recognition of anticipated operating requirements when designing the system, combined with sound subsequent operation within the design capabilities. A listing of these basic principles is as follows:

1. Maintenance of a balanced relationship among power system elements, in terms of size of load, size of generating units and plants, strength of interconnections, and the amount of power being carried on any single transmission channel.

   The adherence to this principle implies:

   (a) avoiding excessive concentrations of generating capacity in one unit, at one location, or in one area;

(b) avoiding excessive concentrations of power being carried on any single transmission circuit, tower line, or right-of-way, as well as through any one transmission station; and

(c) provision of interconnection capability that is commensurate with the size of the system load and with the size of generating units and plants.

2. Provision of transmission capability within the bulk power supply network well in excess of that required for normal transportation of power from generating sources to load centers, so as to maintain a high degree of flexibility in operation and in meeting a wide range of contingencies.
3. Utilization of switching arrangements that would permit effective maintenance of equipment without excessive risk to the interconnected network of ECAR systems.
4. Utilization of adequate switching arrangements and associated relay schemes that do not involve unduly complicated controls and that do not limit the capability of a transmission channel to the extent of causing excessive risk to the interconnected network of ECAR systems.
5. Operation of the interconnected systems of ECAR members so that power interchanges within ECAR and with systems outside ECAR remain within the systems' design capabilities.

Reliability Criteria for Simulated Testing

The simulated testing is to be directed toward assuring that the ECAR bulk power supply network, or any major part thereof, will not suffer a cascading area-wide break-up and collapse under contingencies such as those enumerated below.

1. Sudden outage of any transmission circuit at a time when a combination of any three generating units is out of service.
2. Sudden outage of any double-circuit transmission tower line at a time when a combination of any two generating units is out of service.
3. Sudden outage of any generating unit at a time when any two other generating units are out of service.
4. Sudden outage of all generating capacity at any generating plant.
5. Sudden dropping of a large load or a major load center.
6. Sudden outage of all transmission lines on the same right-of-way.
7. Sudden outage of any transmission station, including all generating capacity associated with such a station.
8. Sudden outage of any tower line at the time when any other one circuit is out of service.

In carrying out simulated testing in accordance with the above criteria, careful attention is to be given to the following:

1. Steady-state, dynamic and transient stability considerations, including three-phase faults at the most critical locations.
2. The effect of slow fault clearing as a consequence of improper relay operation or failure of a circuit breaker to open.
3. Possible occurrence of the above contingencies not only on the interconnected ECAR network, but also on the network of the power systems connected to ECAR.
4. The entire range of operating modes for the interconnected system being tested, including the anticipated range of scheduled power deliveries or receipts.

The simulated testing is to take into account the projected conditions on the systems adjacent to ECAR, making the greatest possible use of data and study results obtained from inter-regional studies with non-ECAR systems.

The criteria for evaluation and simulated testing of the ECAR bulk power supply system have been prepared to meet present and anticipated future conditions as they are visualized today. Since conditions may change with time, the criteria will be periodically reviewed to assure their continued applicability.

APPENDIX VIII–C

ECAR DOCUMENT NO. 2 [1]—DAILY OPERATING RESERVE

The East Central Area Reliability Coordination Agreement provides for the establishment of principles and procedures regarding matters affecting the reliability of bulk power supply within ECAR. It recognizes the need to establish a minimum level of daily operating reserve to be provided by each system and to determine the distribution of that reserve among generating facilities. Daily operating reserve includes spinning reserve, quick-start reserve and interruptible load. Definitions for these and other terms used in this document appear in the glossary attached hereto.

This document presents the daily operating reserve criteria adopted by ECAR members. It shall be reviewed annually and shall be resubmitted each year to the Executive Board for readoption as in the initial instance whether or not changes are to be recommended.

Basis for the Selection of Daily Operating Reserve Requirements

Generating capability in excess of anticipated system load demand is required to assure a high degree of service continuity. This reserve margin is necessary because it is not possible to predict precisely system load demands and because generating equipment is subject to unscheduled shutdowns.

The factors considered in establishing the magnitude of daily operating reserve included unexpected loss of generation, regulation requirements and load forecast error. The nature and characteristics of the various types of generation and interruptible loads which comprise the total operating reserve have been considered in the formulation of these criteria.

The responsibility of a system or group of systems which experiences a sudden loss of generation is to restore the interconnected network to normal frequency and scheduled tie line flows as soon as possible. This places the entire network in the most favorable position to withstand additional unit outages. For the purpose of this document, it was concluded that the ECAR systems, individually or collectively, should be able to restore conditions to normal within ten minutes for any realistic contingency.

Daily Operating Reserve Requirements

Each ECAR member shall have a minimum total daily operating reserve equal to the summation of the amounts set forth in Items 1, 2 and 3 below and determined as follows:

1. An amount equal to 3 percent of the maximum 60-minute integrated clock hour internal load predicted for the day to provide for load regulation and for system frequency regulation. This shall be spinning reserve.
2. An amount equal to 1 percent of the maximum 60-minute integrated clock hour internal load predicted for the day for load forecast error. This amount may be supplied from spinning reserve, interruptible load or quick-start reserve. If provided by interruptible load or quick-start reserve, it must be fully applicable within 20 minutes and it must be utilized as soon as it becomes apparent that it will be needed to meet the load.
3. An amount equal to a specified percentage of the maximum 60-minute integrated clock hour internal load predicted for the current calendar year shall be provided for an unexpected loss of generation. The percentage to be used for each system shall be the weighted average forced outage expectancy for that system. This portion of the operating reserve may be allocated among the acceptable components in any desired combination which is within the following pre-

[1] October 31, 1968.

scribed limits: (a) 0–100 percent spinning reserve; (b) 0–100 percent interruptible load or quick-start reserve which is fully applicable within one minute; and (c) 0–50 percent interruptible load or quick-start reserve which is fully applicable within ten minutes. These components of the operating reserve must be utilized to the extent necessary to offset any loss of generation which may occur within ECAR.

4. The spinning reserve of Item 1 and the spinning reserve portion, if any, of Item 3 shall be allocated among generating units so as to provide a rate of response which will assure that it can be fully utilized in ten minutes or less.
5. In the event of any contingency which reduces the operating reserve level for a system below the minimum value set by these criteria, it shall be the obligation of the deficient system to restore its operating reserve to the stated minimum level as soon as practicable by action within its own system or by scheduled receipts from other systems. If excess daily operating reserves are unavailable to meet the foregoing, the available operating reserves within ECAR shall be redistributed by scheduled receipts and deliveries to the extent necessary to meet the existing situation.

The Operation Advisory Panel shall evalute annually the effectiveness of the daily operating reserve program based on a critical analysis of the actual performance of each system in ECAR. In addition, the panel shall proceed with a detailed study of the development and application of advanced analytical methods for the determination of operating reserves. The panel shall make recommendations for changes in the above program if deemed desirable.

Determination of Daily Operating Reserve

The generating capability rating to be used for units which are scheduled for operation to meet system load and operating reserve requirements will be as designated by each member except that the determination of capability shall be in accordance with a uniform method for determining capability of generating units as may hereafter be recommended by the Coordination Review Committee and approved by the Executive Board. A listing of seasonal capability ratings for each generating unit will be compiled and distributed to each member system from the ECAR Executive Manager's office.

That portion of its daily operating reserve requirements which is specified by Items 1 and 2 will be determined each day by the individual system's operators. The loss of generation obligation which is specified by Item 3 is a constant amount for each day of the period and the amount of reserve to be provided by each system will be computed in advance. A listing of system obligations will be distributed to members of the Coordination Review Committee by the ECAR Executive Manager's office each May and October.

Each system's loss of generation obligation will be derived using its weighted average forced outage expectancy. This average forced outage expectancy will be calculated using the capability rating of and the forced outage rate for each specific unit. The capability ratings will be selected from the listing of seasonal capability ratings mentioned above and the forced outage rates will be derived using methods recommended by the Coordination Review Committee and approved by the Executive Board. Listings of such information will be maintained, as periodically updated, at the ECAR Executive Manager's office and copies will be supplied to the members of the Coordination Review Committee.

Each system shall be responsible for supplying the information necessary for determining the acceptability of quick-start reserve and interruptible loads as components of operating reserve. The qualifications for acceptance will be as recommended by the Coordination Review Committee and approved by the Executive Board. A list of all qualifying components will be compiled and distributed to the members of the Coordination Review Committee by the ECAR Executive Manager's office.

The total operating reserve requirement shall be determined daily by the individual system's operators in accordance with the procedure specified herein. This requirement may then be allocated among the acceptable components of operating reserve. The attachment entitled "Sample Calculation of Minimum Operating Reserve" illustrates the application of the daily operating reserve criteria.

Sample Calculation of Minimum Operating Reserve

Assume five systems, each with a 5,000-MW peak internal load on the day of annual peak. Further assume that each is predicting that this is the day of its annual peak. The systems have different mixes of generating units and varying amounts of quick start generation (10 minute rating) and interruptible loads (1 minute rating).

	A	B	C	D	E
System Operating Reserve Requirements					
Loss of generation (%)	3	2.5	3.5	4	4
Loss of generation (MW)	150	125	175	200	200
4% of peak load (MW)	200	200	200	200	200
Total operating reserve (MW)	350	325	375	400	400
System Non-Spinning Assets					
Quick start capability (MW)	0	125	0	150	150
Interruptible load (MW)	0	0	250	50	125
Allocation of Operating Reserve					
Spinning reserve (MW)	350	212.5	150	200	150
Idle quick start capability (MW)		112.5	....	150	125
Interruptibles (MW)			225	50	125
Total (MW)	350	325	375	400	400

GLOSSARY

Daily Operating Reserve is that amount of generating capability and/or equivalent generation in excess of forecasted daily peak load which is available to provide for load variation and forecast error, frequency regulation, area protection and contingencies such as loss of generating capability. It consists of the following components:

A. Spinning Reserve, which is that generating capability in excess of load connected to the system and ready to take load immediately, and which is capable of being fully applied within 10 minutes.

B. Quick-Start Reserve, which is non-spinning generation that can be synchronized to the system and its capability fully applied within 20 minutes. It may include:

1. Diesel Generators.
2. Combustion Turbines.
3. Hydroelectric Generators.

C. Interruptible Load, which is customer load contractually subject to interruptions and pumped storage or hydroelectric generation in a pumping mode.

Internal Load is the summation of generator net output plus net interconnection receipts, minus net interconnection deliveries.

APPENDIX VIII–D

ECAR DOCUMENT NO. 3 [1]—EMERGENCY PROCEDURES DURING DECLINING SYSTEM FREQUENCY

The East Central Area Reliability Coordination Agreement provides for the establishment of principles and procedures regarding matters affecting the reliability of bulk power supply within ECAR. Consistent with this objective, studies have been made of system performance under conditions of declining system frequency to determine the need for and the extent of a coordinated program of emergency procedures. This document presents the program adopted by ECAR members as a result of these studies.

Basis for the Selection of an Emergency Procedures Program

The promulgated goal of ECAR members is to design and build an interconnected network within the ECAR area which would not be subject to widespread system outages as a consequence of a major disturbance and to develop guidelines for its safe and reliable operation. Precautionary procedures, regardless of this stated goal, are required to meet emergency conditions such as system separation and operation at sub-normal frequency. In addition, coordination of emergency procedures, including the load shedding practices of ECAR companies, both with respect to each other and with respect to neighboring companies outside ECAR is essential.

The basic principles of load shedding are, in the event of a sudden serious emergency, to:

(1) restore the balance between load and generation in the affected area in the shortest possible time and permit the subsequent return to 60 Hz operation, so as to minimize adverse effects on customer service, and

(2) minimize the risk of damage to company and customer facilities and equipment.

[1] October 31, 1968.

The ability to reduce firm customer load in an extreme emergency will not be used as a substitute for system facilities in planning or in normal system operation. It is instead a measure to be taken only after the system has suffered an unpredictable catastrophe which may otherwise lead to widespread system outages.

Program for Emergency Procedures During Declining System Frequency

From 60.0–59.8 Hz, utilize to the extent practicable all operating and emergency reserves. The manner of utilization of these reserves will depend greatly on the behavior of the system during the emergency. For rapid frequency decline only that capacity, on line and automatically responsive to frequency (spinning reserve), and such items as interconnection assistance, and load reductions by automatic means are of assistance in arresting the decline in frequency.

Below 59.8 Hz if the frequency decline is gradual, the system operators, particularly in the deficient area should invoke non-automatic procedures involving operating and emergency reserves. These efforts should continue until the frequency decline is arrested (or until automatic load shedding devices operate at subnormal frequencies).

The steps of the program are as follows:

Step 1: At 59.3 Hz shed not less than 10 percent of system load with automatic load shedding relays. No intentional time delay should be used beyond that absolutely required to avoid improper relay operation.

Step 2: At 58.9 Hz shed additional load in an amount not less than 15 percent of system load existing prior to Step 1 with automatic load shedding relays. No intentional time delay should be used beyond that absolutely required to avoid improper relay operation.

Step 3: At 58.5 Hz, if frequency is declining, take any action necessary to arrest frequency decline. This may include additional load shedding, manual or automatic, and coordinated network separations. This action shall be completed before frequency declines to less than 58.2 Hz.

Step 4: Below 58.2 Hz, isolate generating units in accordance with Appendix I of this document. In the event it becomes necessary for a system to isolate a generating unit at a frequency higher than 58.2 Hz, or a time period shorter than stipulated in the schedule of Appendix I, such system shall also simultaneously disconnect an amount of load equal to that particular generating unit's output. This amount shall be an additional amount over any load previously shed. Automatic isolation of generating units, if employed, should provide two or three seconds time delay to permit temporary frequency excursions below the isolation frequency.

Step 5: If at any time in the above procedure, the decline in area frequency is arrested below 59.0 Hz, the systems in the low-frequency area shall shed an additional 10 percent of their initial loads. Furthermore, each system in the low frequency area shall maintain or increase its generating output to a value corresponding to the full open control valve position until frequency is restored to synchronizing range of the main network.

Step 6: If after 5 minutes the action taken in Step 5 above has not returned area frequency to 59.0 Hz or above, the systems in the low frequency area shall shed an additional 10 percent of their remaining load, repeating on 5-minute intervals until 59.0 Hz is reached. This step must be completed within the time limits outlined in Appendix I of this Document, "Isolation of Power Plants."

Step 7: When area frequency has been established at 59.0 Hz or above the system or systems in the low frequency area shall take any action necessary to permit re-synchronization of the isolated area to the main network.

Step 8: After frequency has returned to synchronizing range the isolated area shall be synchronized with the interconnected systems.

Step 9: Load restorations shall be directed by system operators; normal network operation shall be resumed under the direction of the system operators.

The inter-relationship of the Emergency Procedures Program with the Daily Operating Reserve Requirements which are established in ECAR Document No. 2 is recognized. Operating reserve, as used herein and in ECAR Document No. 2, includes spinning reserve, quick-start reserve, and interruptible loads. Emergency reserve as used herein includes emergency capacity ratings of generation, emergency power obtainable from interconnected systems, load reduction by system voltage adjustment, and load reduction by curtailment of utility company use or special customer uses. As stated, ECAR members will utilize these reserves to the best of their ability. Interruptible loads which are utilized as part of the operating reserve cannot be counted as part of the load shedding obligation. These interruptible loads should be disconnected from the system by automatic devices to assure their removal prior to Step 1 of the recommendations.

In recognition of the dynamic character of the ECAR area and its neighboring systems, the application of all emergency measures during declining system frequency within ECAR should be reviewed on a regular basis and updated as required to meet changing system conditions.

Appendix I

Isolation of Power Plants

It is recognized that serious damage to turbines can be inflicted by loaded operation at subnormal speed. Although it is desirable to maintain service continuity, it also would be most imprudent to allow equipment to suffer major damage which would impede the restoration of service after a major disturbance.

To preclude the possibility of damage to equipment and still maintain reliable operation of generating plants, coordination of emergency procedures during low frequency operation is essential.

Program for Isolation of Generating Units During Low System Frequency

Plant operators shall isolate generating units from the system when all of the procedures performed by the system operators as stipulated in ECAR Document No. 3—"Emergency Procedures During Declining System Frequency" have been unsuccessful in returning system frequency to 59 Hz or above.

Isolation of the units will be done on the following schedule. The time periods and frequencies allowed are designed to assure that all possible opportunity is given for the system to recover and yet protect the generating units from damage. Adjustments of the times and frequencies stated may be necessary for specific units due to the accumulative effect of blade fatigue over the life of the turbine or to conform with manufacturers limitations.

60.0 to 59.0 Hz	Unlimited.
Below 59.0 Hz	30 minutes minimum time before unit isolation.
Below 58.5 Hz	7 minutes minimum time before unit isolation.[1]
Below 58.2 Hz	Unit isolation without time delay.

[1] This 7 minutes is part of the total time of 30 minutes allowed below 59 Hz.

Every effort should be made by the operator to maintain unit auxiliaries and, if possible, a local load. This is to allow rapid re-synchronizing of the unit to the main network to aid in restoration of the system.

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APPENDIX VIII–E

ECAR DOCUMENT NO. 4[1]—METHOD FOR THE UNIFORM RATING OF GENERATING EQUIPMENT

The East Central Area Reliability Coordination Agreement provides for the establishment of principles and procedures regarding matters affecting the reliability of bulk power supply within ECAR. This document presents the criteria to be used for uniform rating of generating equipment on the systems of ECAR members.

Definitions used in this document appear in the glossary attached hereto.

This document shall be reviewed annually and shall be resubmitted each year to the Executive Board for readoption as in the initial instance whether or not changes are to be recommended.

Basis for the Selection of a Method for Uniform Rating of Generating Equipment

Generating capability to meet the system load and provide the required amount of reserves is necessary to assure the maximum degree of service reliability. This generating capability must be accounted for in a uniform manner which assures the use of realistically attainable values when planning and operating the system or scheduling equipment maintenance.

To meet these requirements, guides are herein established for determining the rating of the individual generating units. These guides define the framework under which the ratings are to be established while recognizing the necessity of exercising judgment in their determination. The tests required are functional and do not require special instrumentation or procedures. They are designed to demonstrate that the ratings can be obtained for the time periods required under normal operating conditions for the equipment being tested.

It is intended that the terms defined and the ratings established pursuant to this document shall be used by all members for the following ECAR purposes:

1. Determining reserves.
2. Scheduling operating capability.
3. Maintenance scheduling.
4. Reports authorized for release by ECAR to regulatory agencies, news media, and industry organizations.

Method for the Uniform Rating of Generating Equipment

Net Demonstrated Capability will be the basic rating of generating equipment. Adjustments will be made in this rating to establish Net Seasonal Capability.

A. *Determining Net Demonstrated Capability*—The following guides shall be applied in determining the value of Net Demonstrated Capability. Guides 1–5 are general in nature, 6–8 are concerned with specific types of generating units, and 9 outlines the test procedures.

1. The Net Demonstrated Capability will be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others. The Net Demonstrated Capability will be determined as a group for common-header steam plants or multiple-unit hydro plants and each unit assigned a rating by apportioning the combined capability among the units. Each turbine-generator and each boiler in a common-header plant will also be assigned a rating which reflects its individual capability. It is intended that frequent changes in Net Demonstrated Capability be avoided. The reported capability is therefore a figure which should not be altered until the accumulated evidence of tests and analyses of operating experience (especially reported condition deratings) indicate that a long-term change has taken place.

[1] July 1, 1969.

2. This capability will be determined with no allowances made for participation in system load variation or distribution of spinning reserve.

3. This capability will reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

4. This capability will exclude the temporary higher output attainable immediately after a new unit goes into service or immediately after an overhaul.

5. Extended capability of a unit or plant obtained through bypassing of feedwater heaters, by utilizing other-than-normal steam conditions, or by abnormal operation of auxiliaries in steam plants; or by utilization of reservoir storage in hydro plants; or by operation of combustion turbines or diesel units above base rating; may be included in the Net Demonstrated Capability if owning company desires to do so and the following conditions are met:

a. The extended capability based on such conditions will be available for a period of not less than four continuous hours when needed.

b. Normal procedures have been established so that this capability will be made available when requested by the dispatcher.

c. Such capability will be made available within the time limits specified in ECAR Document No. 2, *Daily Operating Reserve.*

6. In the case of generating equipment with steam turbines as the prime movers:

a. Turbine exhaust pressure will be corrected to that normally attained in the winter months.

b. The Net Demonstrated Capability of nuclear units will be determined taking into consideration the fuel management program of the unit and any restrictions imposed by governmental agencies.

7. Combustion turbines or diesel peaking units will be rated at the cold weather condition of ambient temperature.

8. Hydroelectric Plant—Net Demonstrated Capability will be that portion of its total installed generating capability which can perform the same function on that portion of the load curve assigned to it as alternative steam generating equipment could perform. This capability will be based on December average water conditions.

9. The Net Demonstrated Capability will be determined by testing. Such test or tests shall be of sufficient duration to assure that these capabilities are adequate to satisfy the load requirements of the owning system and will conform to the following:

a. A test of a steam electric generating unit or plant will be run for a period of not less than 2 continuous hours. A test of combustion turbines, diesels, or hydro will be run for not less than 30 minutes.

b. Steam conditions will correspond to the operating standard established by the owning company for the unit or plant.

c. The steam generator will be operated with the regularly used type and quality of fuel.

d. A steady output will be maintained to the extent possible during a test period.

e. If the total capability of a plant is materially affected by the interaction of its parts (such as a common-header plant), a test of the entire plant will be performed and the Net Demonstrated Capability of the individual units determined by prorating the total output.

f. All equipment when tested will be in average operating condition with all auxiliary equipment needed for normal operation in service.

g. Energy consumption by auxiliary facilities common to the entire plant (for example, coal-handling or lighting) will be distributed over the appropriate units in the plant, and will represent the consumption normally experienced during the high-load period of the day.

h. Net Demonstrated Capability will be no greater than the mwhr/hr. integrated output for the test period corrected for the Seasonal Adjustment and Condition Derating in effect at the time of the test.

i. Test will be performed in a 12-month cycle or more frequently if appropriate to provide the basis for determining Net Demonstrated Capability.

j. Any deactivated generating equipment returned to active status shall be tested within a reasonable length of time.

B. *Determining Seasonal Adjustment.*—The monthly variation will be determined by computation based on analysis of operating records or test.

C. *Determining Condition Derating.*—Such derating will be determined by computation based on analysis of operating records or by test.

Reporting of Uniform Rating of Generating Equipment

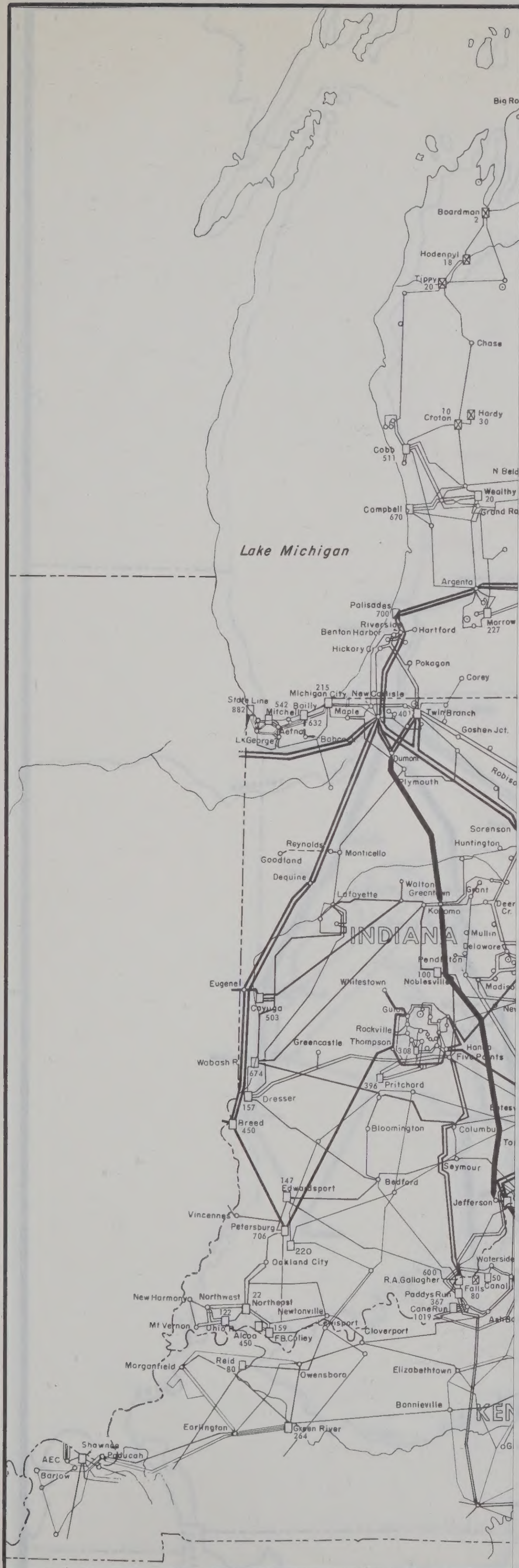
The Net Demonstrated Capability, test results and the computations used in determining the Seasonal Adjustment and Condition Derating of each generating unit at the time of test will be submitted annually, or more frequently if appropriate, to the ECAR Executive Office on a standard ECAR form. Seasonal Adjustment factors, with necessary supporting data, will be submitted for each generating unit for each month of the year.

GLOSSARY

The following is a glossary of terms used in this report:

1. *Net Demonstrated Capability* is the winter rating of generating equipment. It is the steady hourly output which generating equipment is expected to supply to system load, exclusive of auxiliary power.
2. *Seasonal Adjustment* is the predicted variation from Net Demonstrated Capability of generating equipment due to seasonal factors which generally include variation in ambient temperature, condensing water availability and/or temperature, reservoir levels, scheduled reservoir discharge, or other causes.
3. *Net Seasonal Capability* is the Net Demonstrated Capability of generating equipment after seasonal adjustment. The Net Seasonal Capability will be declared on a monthly basis.
4. *Condition Derating* is the day-to-day variation from Net Seasonal Capability of generating equipment justified by such factors as turbine, boiler, and condenser deposits, quality of fuel, removal of turbine blades, restricted fan or pump output.

(Outages of boilers of turbine-generators in common-header installations and outages of unit auxiliaries will be considered as partial outages and not as a Condition Derating.)



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C. *Determining Condition Derating.*—Such derating will be determined by computation based on analysis of operating records or by test.

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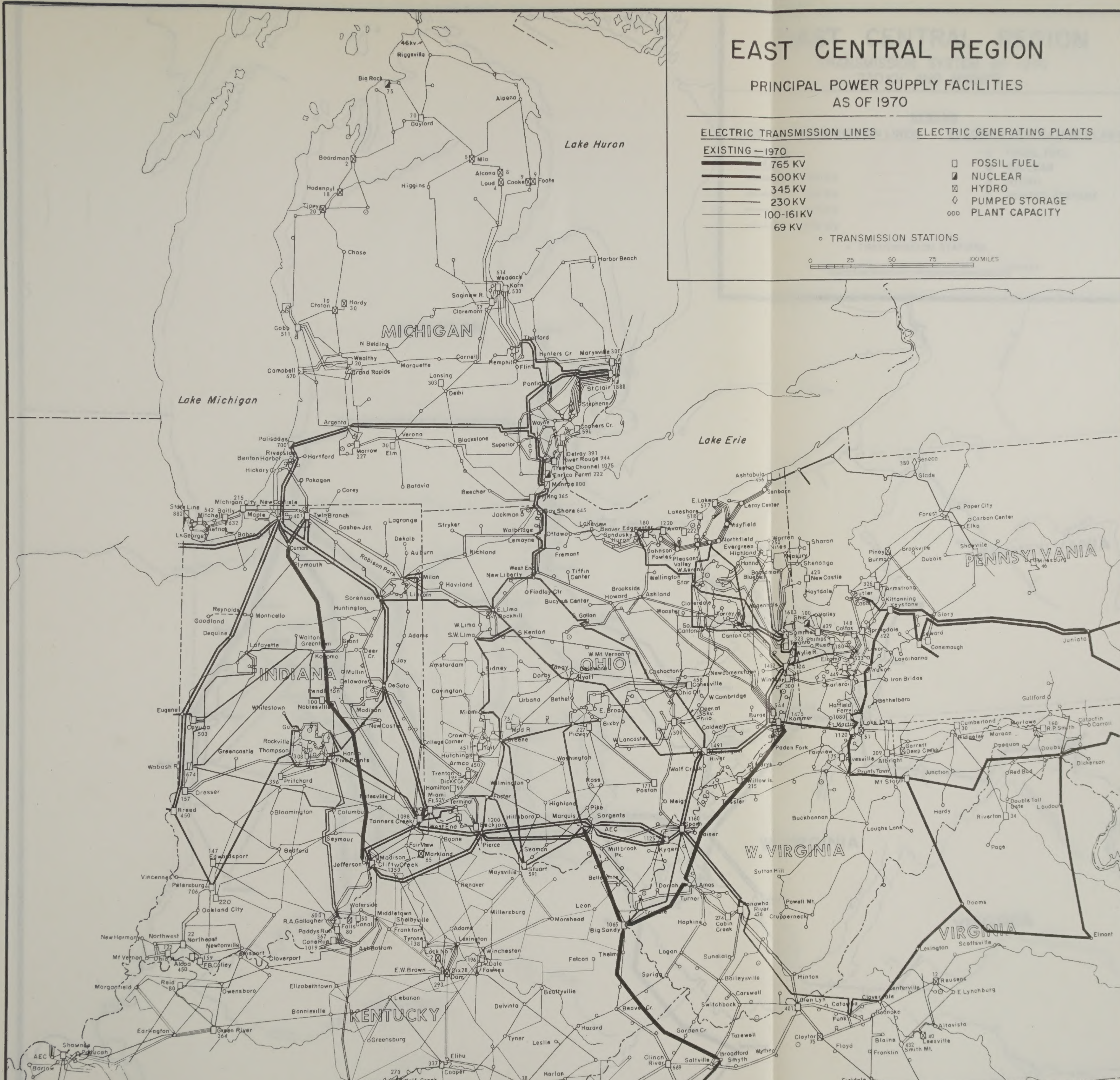

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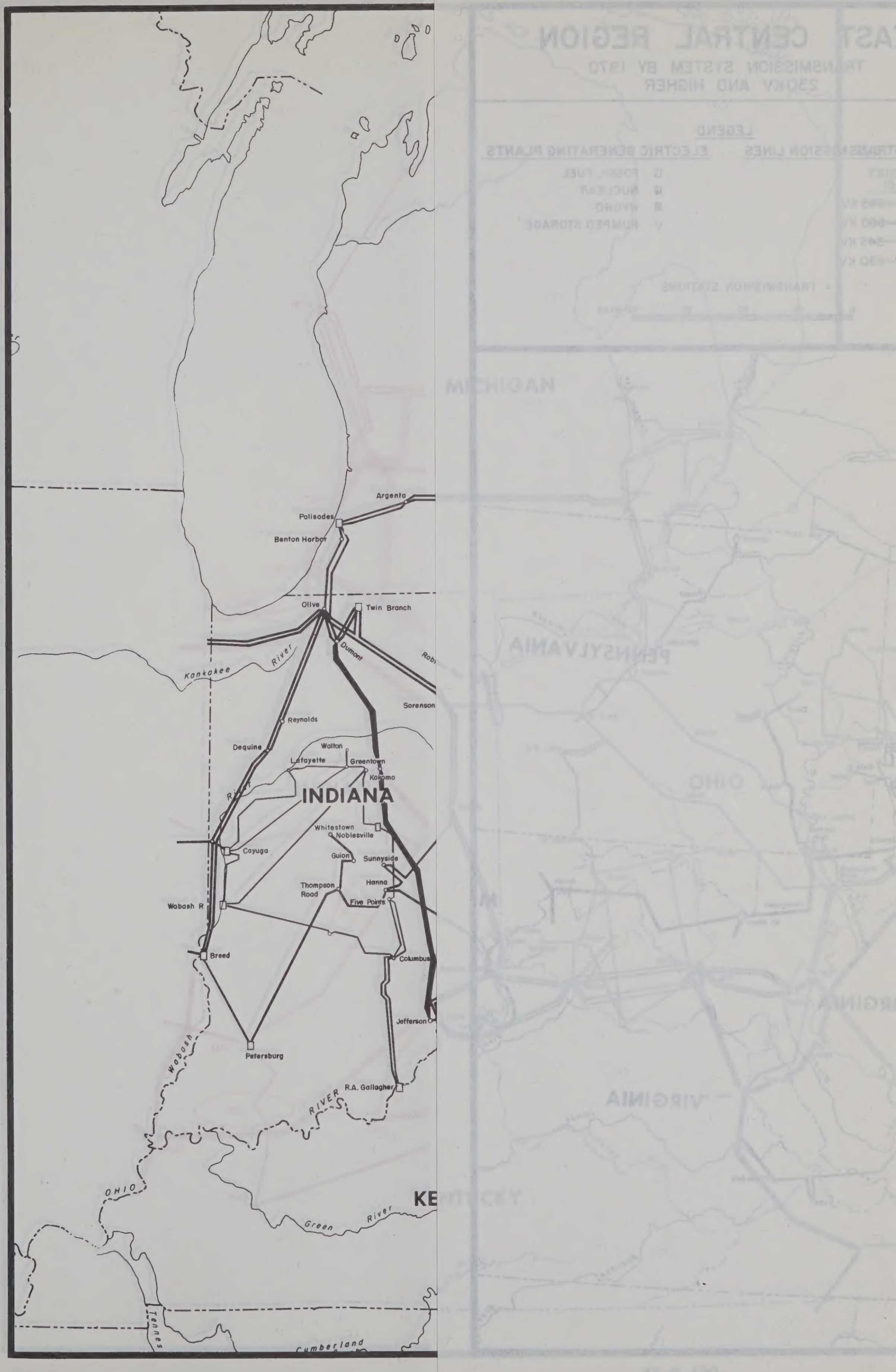

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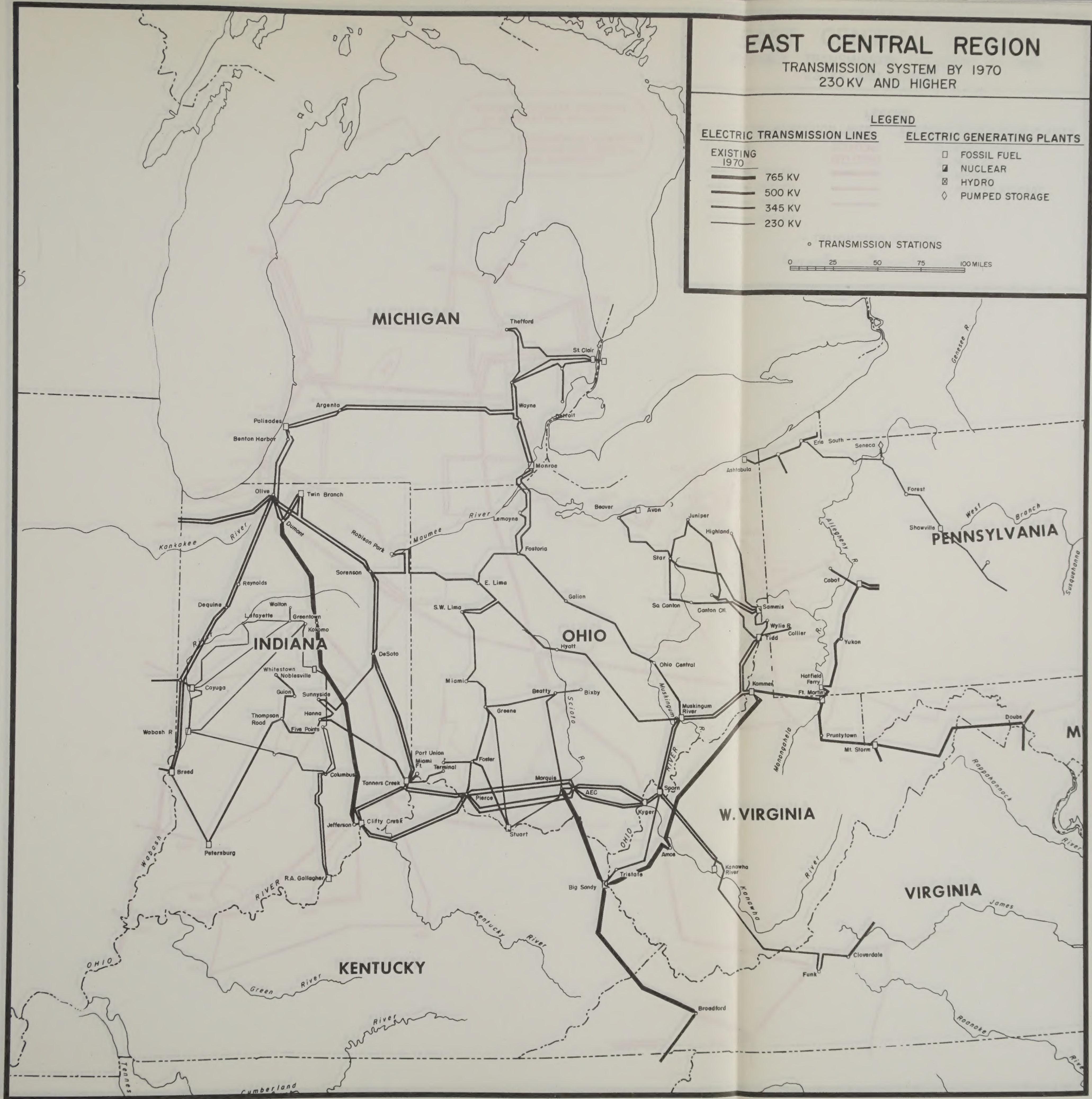

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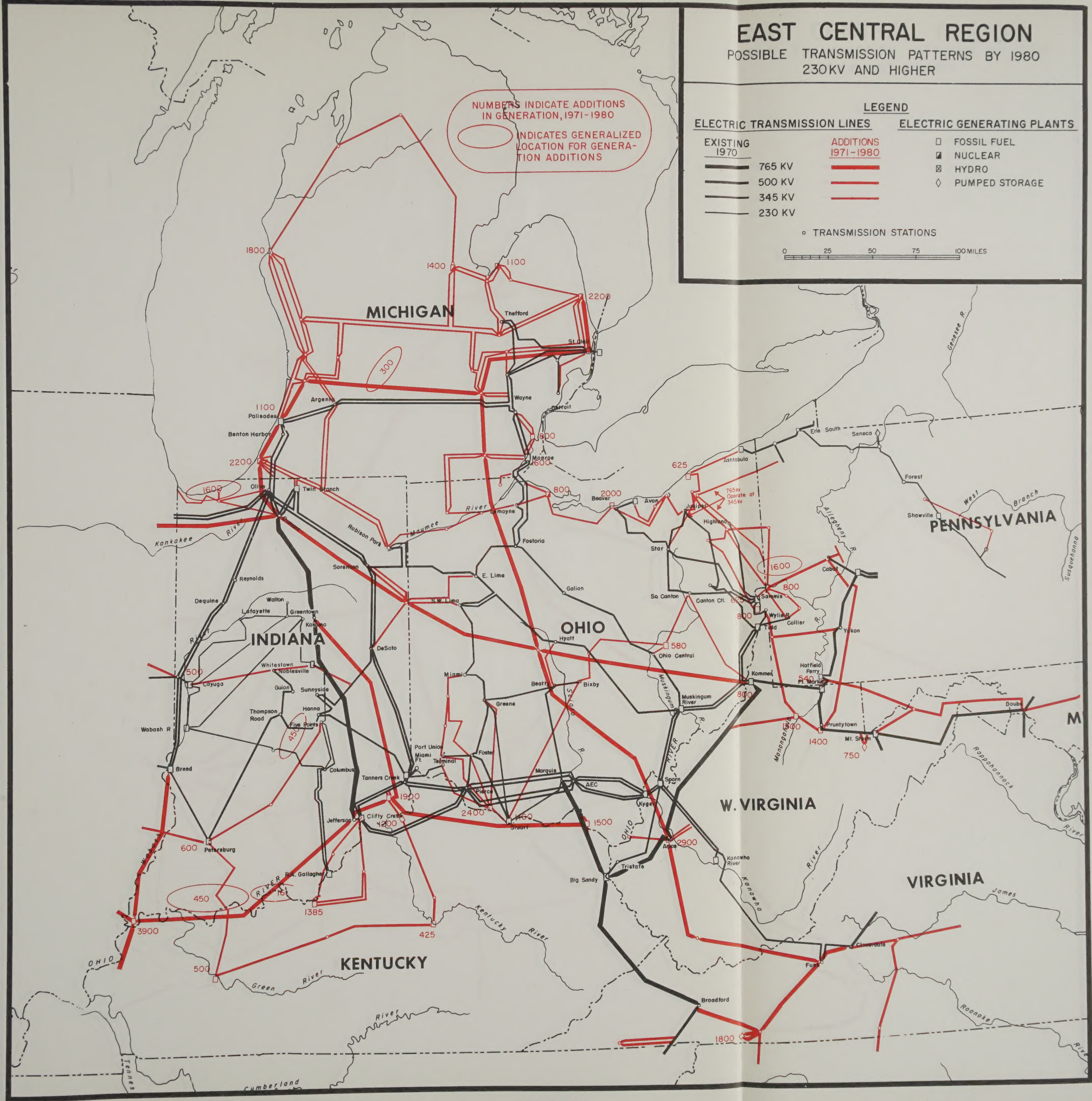

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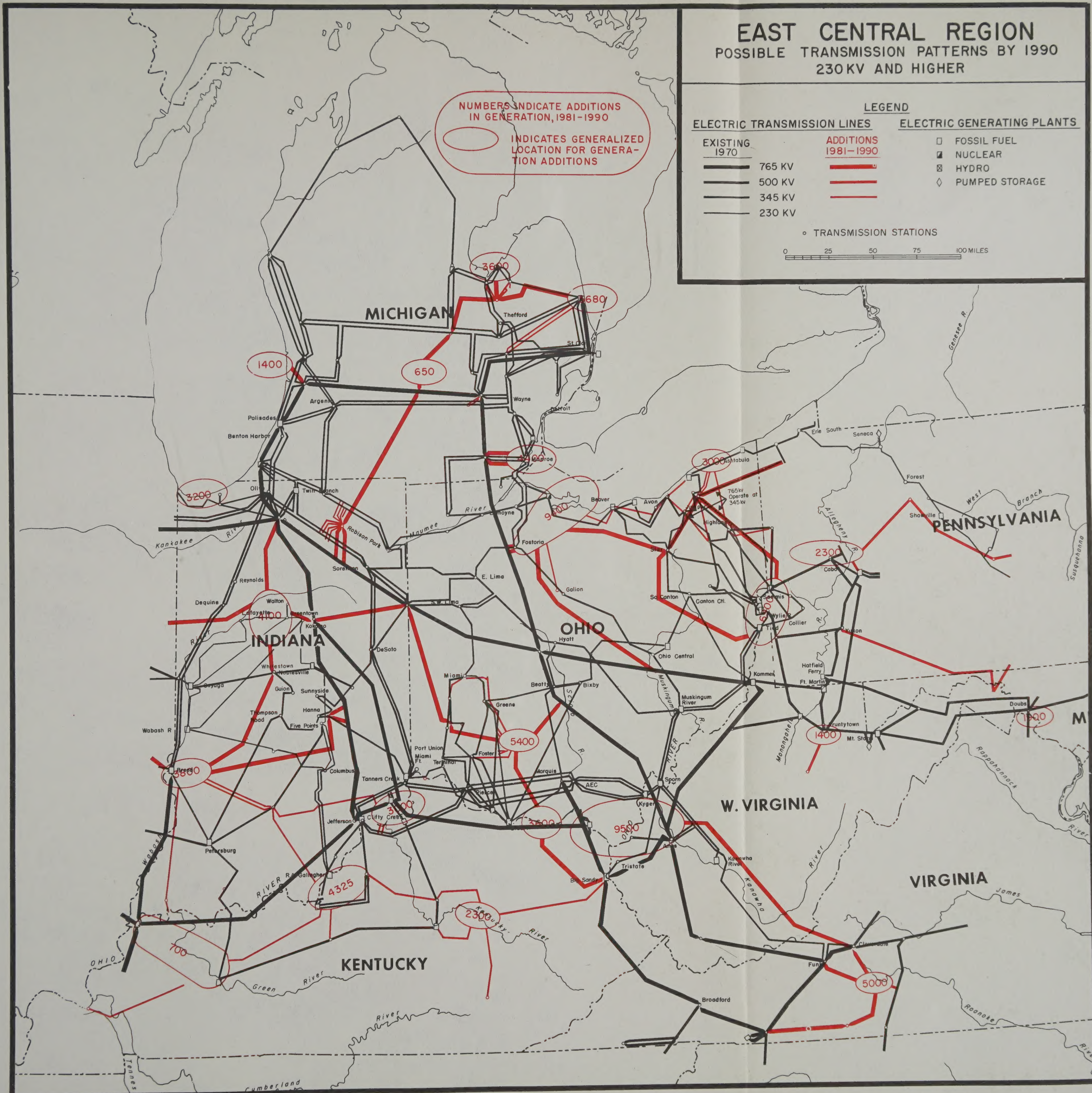

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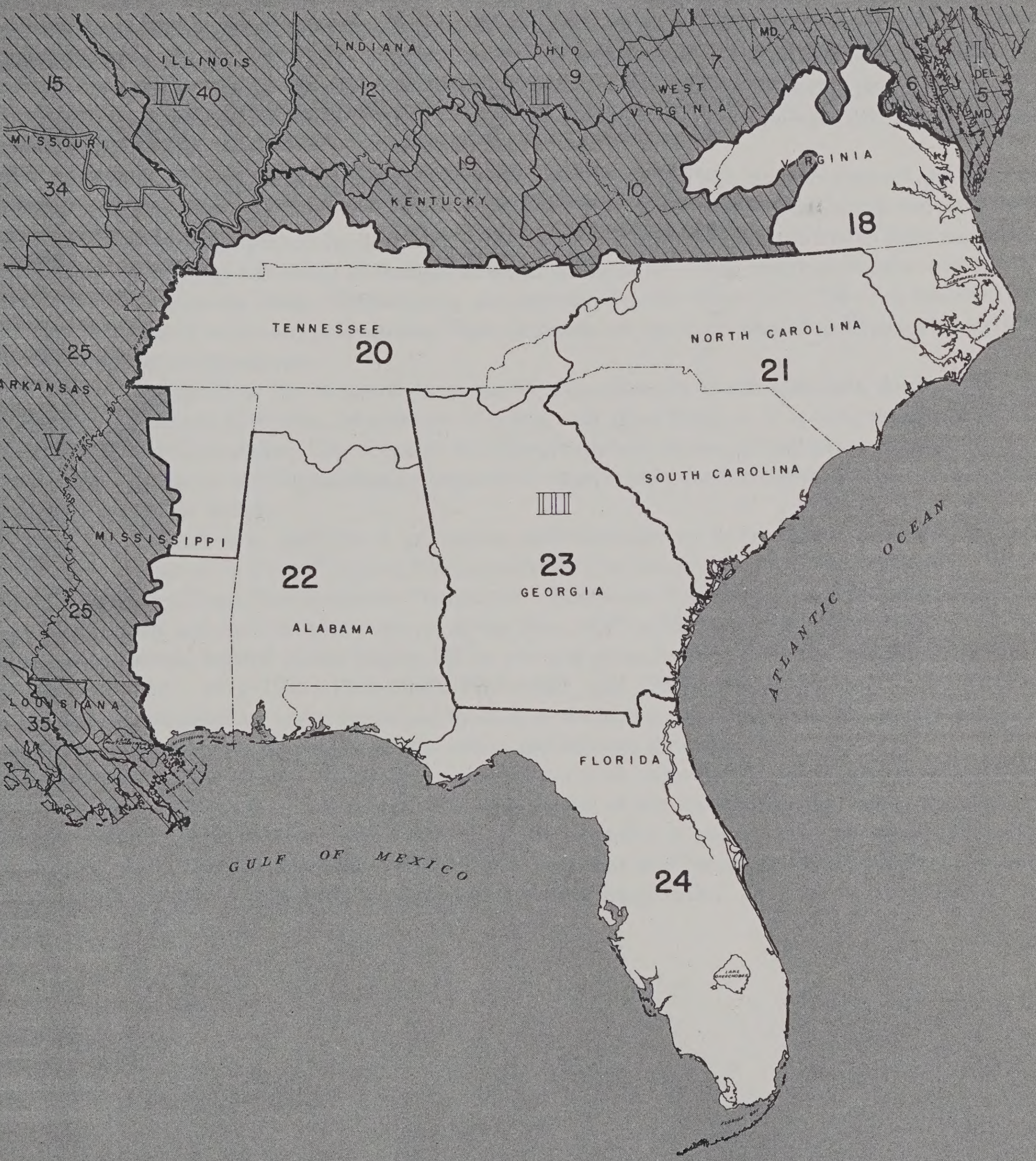
ELECTRIC POWER IN THE SOUTHEAST

1970 - 1980 - 1990



A REPORT
TO THE FEDERAL POWER COMMISSION

PREPARED BY
THE SOUTHEAST REGIONAL ADVISORY COMMITTEE

APRIL 1969

PREFACE

The Southeast Regional Advisory Committee, representing all segments of the electric utility industry, was established by the Federal Power Commission in March 1966 to assist in the Commission's continuing National Power Survey Program. Members of the Committee are listed on the following page. The specific purpose of the Committee was to review power system planning and operating policies and practices. This report outlines these studies.

Since the Commission issued the National Power Survey Report in 1964, the phenomenal growth continues in the utilization of electric power in the Southeast. This stems largely from continued industrial development and expansion. Spectacular increases in power demand have also resulted from a large expansion of domestic and commercial use owing to changes in social habits as the retail customer became adjusted to increased use of power in the home. Furthermore, the national defense effort since 1964 has continued to create power demands of enormous proportions. These demands are currently requiring large scale increases in the power supply of the Southeast.

The area studied includes the States of Alabama, Florida, Georgia, North Carolina, South Carolina, Tennessee, and portions of Kentucky, Mississippi, Virginia, and West Virginia. It is designated Region III by the Federal Power Commission. The scope of the report involved studies of load projections to the year 1990, patterns of generation and transmission, programs of coordination, fuel and water resource availability, and projected economic trends.

Reports on load forecasts, patterns of generation and transmission, hydroelectric potential, and coordination were prepared by Task Forces or Subcommittees. The chapter on Fuels was abstracted from a report prepared by the Fossil Fuel Resources Committee—Northeast, East Central, and Southeast Regions.

The Task Forces and Subcommittees surveyed the plans of 25 utilities, representing over 98 percent of the energy requirements, located within Region III for plans of expansion of generation and transmission for the periods 1968–1970; 1971–1975; 1976–1980; 1981–1985; and 1986–1990. In general, the patterns of generation and transmission are those developed by each of the major coordination areas within the region, taking into account existing power contracts both within and between the areas.

The Committee acknowledges and is appreciative of the work performed by the Task Forces and Subcommittees in the preparation of this report. It is the opinion of the Committee that the plans outlined herein will provide a useful general guide to the future development of power in the Southeast. However, the Committee would like to emphasize that these load forecasts and future development plans are only broadly indicative of the load growth and plans required to meet this growth.

LIST OF MEMBERS—SOUTHEAST REGIONAL ADVISORY COMMITTEE

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James E. Watson, Asst. Mgr. of Power, Tennessee Valley Authority, Chattanooga, Tenn. 37401

A. M. Williams, Jr., President, S.C. Electric & Gas Company, 328 Main Street, Columbia, S.C. 29201

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[1] Member March 1966–November 1967. Chairman effective November 24, 1967, succeeding W. B. McGuire, President, Duke Power Company.

[2] Succeeded R. M. Hutcheson, Senior Vice President, Virginia Electric and Power Company, April 18, 1967.

[3] Resigned June 2, 1967.

[4] Retired February 28, 1969.

[5] Appointed December 14, 1967.

[6] Appointed December 22, 1967.

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SUMMARY

Structure of the Industry

The Southeast Region, Federal Power Commission statistical Region III, encompasses Power Supply Areas 18 and 20 through 24. The Power Supply Areas are usually associated with the following states: 18 with Virginia, 20 with Tennessee, 21 with North and South Carolina, 22 with Alabama, 23 with Georgia, and 24 with Florida. The Southeast Region has an area of about 355,000 square miles and in 1967 the population exceeded 30 million.

At the end of 1967 there were 563 systems in the Southeast Region engaged in one or more of the three distinct functions of generation, transmission, and distribution as required in the production and delivery of electricity to about 10.5 million ultimate consumers. The public non-Federal ownership group, which includes municipal, state, and county entities, accounts for 329 of the 563 systems in the region. Cooperatives, the next largest ownership group, accounts for 193 systems. Investor ownership accounts for 30 systems, industrial ownership for nine systems, and Federal ownership for two systems.

Development of the utility industry in the Southeast Region over the years has led to the formation of the TVA System, The Southern Company System, the Florida Group, and the CARVA Pool. These four coordination areas include 17 larger systems along with a majority of the other systems which are basically distributors with their bulk power supply interests in the 17 larger systems. This group accounts for more than 97 percent of Region III's power requirement. Among those not included in the 97 percent are 15 isolated systems with annual requirements equal to about 0.5 percent of Region III total.

Some additional potential for further pooling and coordination still exists in Region III but this, however, is small.

Peak Load Forecasts

The load estimates for the Southeast Region have been updated from those published in the 1964 National Power Survey and extended to 1990, an additional 10 years.

The Southeast Regional Advisory Committee solicited load forecasts from the 25 major utility systems which accounted for over 98 percent of the energy requirements for Region III in 1965. The familiarity which each utility has within its area permits a more accurate evaluation of factors affecting the use of electricity. The factors considered are population, size and amount of industry, weather conditions and their effects on heating and cooling loads, and competitive forms of energy. Shown below are the Region III coincidental peaks for each of the 10-year periods 1970–1990:

Year	*Peak Demand MW*
1970	52, 960
1980	109, 270
1990	210, 400

All estimates are subject to changing conditions. It is presumed, however, that the load forecasts for the early years are reasonably accurate. However, projections for the later years are subject to many unknown influences and tend to be less accurate. The long-range projections should form a reasonable foundation for the development of generation and transmission patterns.

In 1965 the coincidental peak demand for Region III was 33,811 megawatts. By 1970 the demand is expected to increase by more than 56 percent, or an average annual growth of 9.4 percent. By 1980 the growth in demand over 1965 is estimated to be about 223 percent or better than an average annual increase of 8.1 percent. A comparison of the 1965 demand and the 1990 demand shows an increase of over 522 percent or an average annual increase of 7.6 percent.

Generation and Transmission

The Regional Advisory Committee surveyed the plans of 25 utilities in Region III for expansion of generation and transmission facilities. The Commit-

tee also surveyed the status of and plans for coordination of bulk power supply facilities among the utilities, including current and future utilization of load diversity, as a means of reducing generating capacity.

Generating capacity additions of 193,528 megawatts are contemplated by the Southeast utilities to meet the annual peak load of 210,400 megawatts projected for Region III in 1990. Both large fossil-fired and nuclear generating type plants are included in projected capacity additions for base load operation. Conventional hydroelectric capacity additions forecast by the utilities amount to 2,198 megawatts and pumped-storage capacity additions for peaking purposes total about 8,500 megawatts. A total of 993 megawatts of thermal peaking capacity is projected by 1990, of which 490 megawatts will be located in Florida where terrain considerations limit conventional hydroelectric and pumped-storage developments.

The maximum and average sizes of fossil-fired and nuclear turbogenerating unit additions are expected to increase in future years. During the period 1970–1990 the maximum size of fossil-fired units is expected to increase from 1,130 to 1,500 megawatts and the average size from 447 to 744 megawatts. During the same period the maximum size of nuclear units is expected to increase from 1,065 to 2,000 megawatts and the average size from 842 to 1,181 megawatts.

Seasonal diversity exchanges between systems which have their largest loads in summer and other systems which have their largest loads in winter are mutually beneficial. Seasonal exchange agreements, involving utilities in the Southeast Region, provide a basis for the present seasonal diversity exchange of some 2,000 megawatts. The largest single exchange agreement is for 1,500 megawatts between TVA and the South Central Electric Companies in Region V. A comparison of the loads of summer and winter peaking systems in future years indicates that opportunities for additional seasonal exchange in the period 1980–1990 appear to be quite limited.

Future transmission patterns indicate a continuation of the EHV line development started in the early 1960's. Substantial amounts of 230-kilovolt transmission have been built in most sections of Region III and there are two notable installations of 500-kilovolt transmission. One of these is designed to accomplish seasonal diversity exchange between TVA and the South Central Electric Companies and the other is the 500-kilovolt system associated with the Virginia Electric and Power Company's mine-mouth plant. In certain areas of Region III where steam plants can be located relatively close to load centers this factor favors transmission at 230 kilovolts as being more economical than 500 kilovolts in those areas. In other areas conditions are substantially different, and special factors may indicate the use of 500-kilovolt transmission. For the entire Region about 4,150 miles of 500-kilovolt transmission are forecast for 1980 and 9,019 miles by 1990. Because of the factors noted above, that is, the relative intermediate distance between load and generation, the 500-kilovolt system is expected to suffice through the 1980's. The utilities in the Region will continue to participate in the programs currently under way concerning the problems of EHV systems and look forward to the selection of a level which will afford the greatest benefits when a voltage about 500 kilovolts becomes necessary.

Environmental Consideration

The concern of the general public for preservation of the quality of natural resources and environment is shared by the Southeast utilities. Utility managements are deeply committed to making their power facilities compatible with the environmental quality needed for public health and enjoyment. Today many Southeast utilities have a full time environmental staff, the sole responsibility of which is to determine the compatibility of new facilities with their surroundings and evaluate the effects of existing facilities and determine what can be done to make them more compatible. The rapid load growth expected in the Southeast makes it imperative that early solutions be found to the problems of best use of environmental and natural resources for bulk power supply, while protecting them for public health and enjoyment.

Coordination

Coordination of operating procedures and planning for reliability of power supply are in effect between the various systems in the Southeast. This is being implemented by Reliability Coordination Agreements between neighboring systems and pools, as well as by joint study programs conducted by systems on a less formal basis. Discussions are now being held to put into effect other similar formal agreements.

In most cases, the work involved in coordination is carried out by committees or special working groups. These committees meet periodically for the purpose of discussing problems and implementing studies leading to increased reliability. These discussions and studies deal with matters such as generation and transmission planning, construction schedules, operation, maintenance schedules, spinning reserve requirements, and mutual assistance during emergencies.

Undeveloped Conventional Hydroelectric Potential

The appraisal of undeveloped conventional hydroelectric potential in the Southeast included a review of 216 sites. After eliminating 185 of these sites for various reasons, the remaining 31 were studied in more detail. Four of the 31 sites were combined as a single project leaving a total of 28 developments. The potential undeveloped capacity represented by these 28 projects totals 4,614 megawatts.

A relative feasibility index was developed for each of the 28 projects by limiting project costs and values to power and recreation only. By this method it was found that nine of the projects with a total of 1,378 megawatts of undeveloped potential show economic promise and may be brought into service by 1980. Five additional projects that are less attractive than the previous nine may be developed by 1990, if other multiple purposes are included to enhance their feasibility. The total conventional hydroelectric potential of these five projects is 785 megawatts. Development of the 14 remaining projects with hydroelectric power as their primary purpose appears unlikely.

Fuels

Fossil fuels accounted for about 89 percent of the total electric generation in the Southeast Region during 1966. Large amounts of coal originating at mines in West Virginia, western Kentucky, and Alabama, and smaller shipments from Illinois and Tennessee accounted for 74 percent of the generation by fossil fuels. Fuel oil (residual) has been used extensively in Florida and accounted for about eight percent of the electric generation in 1966. Gas delivered by pipeline from Louisiana and Texas accounted for about seven percent of the generation in 1966. Use of gas as a boiler fuel is limited mainly to pipeline valley periods. The remaining 11 percent of generation was produced by hydraulic prime movers.

In 1966 over 63 million tons of coal were used at generating plants of the Region along with 28 million barrels of oil and about 141 billion cubic feet of gas.

Estimates of fossil fuel requirements for 1990 show a need for 121.5 million tons of coal, 18.7 million barrels of oil, and over 422 billion cubic feet of gas. Cost of coal has been dropping owing to improved mining technology and tends to increase owing to increased labor and transportation costs. Unless technology is able to produce more coal per man-hour, future coal costs will increase. Gas prices are up about five percent in the period between 1960 to 1966. It is expected that residual oil production will be less in the future owing to the fact that refineries can produce more profitable products using residuals from crude oil.

Unit trains have served to reduce coal transportation costs. Mine-mouth power generating facilities in coal producing areas have reduced both transportation and coal storage costs. For the future, however, the results of this Committee's survey indicate increasing cost of coal at plants for electric generation. The advent of EHV has aided in carrying the energy production from mine-mouth plants to market.

The Southeast Region does not currently have nuclear units on line. However, 23 units are scheduled for service by 1975. The Private Ownership of Special Nuclear Materials Act of 1964 permits the orderly transfer of radioactive material from Government to private ownership. This along with the discovery of additional uranium reserves and the promise of breeder reactors within the next 15 years should greatly assist in increasing the supply of nuclear fuel. Indications are that nuclear power will assume an ever increasing role in power production.

An addendum to the fuels report prepared June 2, 1969, shows that, at least for the short run, fuel oil and natural gas consumption in the Southeast Region has taken a decided upward trend from that forecast in the report. This upward trend is due to greater use of electric power, delayed nuclear plants, accelerated air pollution control programs, increased cost of railway freight and coal, decreased cost of fuel oil, and availability of low sulphur oil.

CHAPTER I

STRUCTURE OF THE INDUSTRY

General

The Southeast Region is one of six regions in the continental United States for which the Federal Power Commission established a Regional Advisory Committee to make studies to be used for updating the 1964 National Power Survey. The Southeast Region has an area of about 355,000 square miles which is 17.5 percent of the area of the continental United States. In 1967 the population in the region exceeded 30,000,000 which is about 15.4 percent of the population of the continental United States.

The Southeast Region, Federal Power Commission statistical Region III, encompasses Power Supply Areas 18 and 20 through 24. The boundaries of these power supply areas are delineated by the service areas of the electric utilities, groups of utilities, and operating power pools. Region III includes all of North Carolina, South Carolina, Georgia, Florida, Alabama, and Tennessee along with parts of Virginia, Kentucky, Mississippi, and West Virginia.

Figure 1 shows the geographical extent of Region III by states and power supply areas. The power supply areas are usually associated with the following states: 18 with Virginia, 20 with Tennessee, 21 with North and South Carolina, 22 with Alabama, 23 with Georgia, and 24 with Florida. The power supply areas may be grouped into four distinct coordination areas within which a high degree of coordination now exists. The four coordination areas are also shown on Figure 1 and will be referred to in this report as follows:

PSA	*Coordination Areas*
20	TVA System
22 and 23	The Southern Company System
24	The Florida Group
18 and 21	CARVA Pool

Composition of the Power Industry in the Southeast Region by Class of Ownership and Size

At the end of 1967 there were 563 systems in the Southeast Region engaged in one or more of the three distinct functions of generation, transmission, and distribution as required in the production and delivery of electricity to about 10.5 million customers. Information on the class of ownership, peak loads, annual energy requirements, and installed generating capacity for these systems has been assembled by the staff of the Atlanta Regional Office of the Federal Power Commission from annual Power System Statements.

The 563 systems do not include the Southeastern Power Administration, the marketing agency for power generated at Corps of Engineers projects in the Southeast Region, since the output of the projects is resold by a number of the other systems that are included. Of the 563 systems, 554 are electric utility systems and nine are industrial concerns. The nine industrial concerns are included because eight of them make incidental deliveries of electricity to ultimate consumers and the generating facilities of the other one are coordinated with the operations of neighboring utilities.

Number of Systems by Class of Ownership

The electric power industry is made up of four distinct ownership segments: Investor-owned, state and local public agencies, cooperatives, and Federal agencies. The number of systems in each ownership classification at the end of the year 1967 is summarized in Table 1. The public non-Federal ownership group in the table includes municipal, state and county entities. This ownership group accounts for the greatest number of systems—329 of the 563 systems in the region. Cooperatives, the next largest ownership group, account for 193 systems. Investor

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SOUTHEAST REGIONAL ADVISORY COMMITTEE
REGION III
POWER SUPPLY AREAS AND POWER POOLS

Figure 1

ownership accounts for 30 systems, industrial ownership for nine systems, and Federal ownership for two systems.

Number of Systems by Size

There are several measures used in the utility industry to categorize a system by size. Those normally used include generating capacity, peak load, annual energy requirements, transmission line mileage, number of customers served, revenue, etc., depending, of course, on what phase of utility operation is under consideration. As a measure of system size from a power supply standpoint the annual system peak load which is usually readily available and well adapted for comparison of system sizes is considered a good criterion.

The 1965 peak load data for the 563 systems in the region are allocated to 12 selected load intervals ranging from 0 to 25,999 megawatts in Table 1. Of the total, 31 systems had peak loads exceeding 100 megawatts and 532 had peak loads less than 100 megawatts. Of the 532 systems with peak loads less than 100 megawatts, 430 are concentrated in the two load intervals below 25 megawatts. This allocation indicates that there are relatively few large systems and a large number of small systems. The majority of the small systems, however, are a part of a larger system with regard to power supply.

In 1965 the TVA System had the largest peak load in the region such load being slightly over 12,800 megawatts. The peak loads of 12 investor-owned systems in the region exceeded 100 megawatts and ranged up to the 3,200 to 6,399 megawatts load interval shown in Table 1. There are 11 public non-Federal Systems in Table 1 that had peak loads in excess of 100 megawatts and some that ranged up to the 800 to 1,599 load interval. The peak loads of six cooperative and one industrial system are over 100 megawatts. All are in the 100 to 199 megawatts load interval shown in the table.

Participation in Southeast Region Power Pools

Development of the utility industry in the Southeast Region over the years has led to the formation of the TVA System, The Southern Company System, the Florida Group, and the CARVA Pool. Details on pooling agreements and the joint programs and procedures adopted by these systems to attain maximum economy and reliability of power

TABLE 1

Southeast Region—Number of Electric Systems by Size of Peak Load (1965) and Class of Ownership (1967)

System peak load	Investor owned	Federal	Public non-Federal [1]	Cooperative	Industrial [2]	Total
12, 800–25, 999		[3] 1				1
6, 400–12, 799						
3, 200– 6, 399	2					2
1, 600– 3, 199	4					4
800– 1, 599	2		2			4
400– 799	3		3			6
200– 399			2			2
100– 199	1		4	6	1	12
50– 99	1		19	14		35
25– 49	1		46	19	1	67
13– 24	1		48	56	1	106
0– 12	15	1	205	98	6	324
Total	30	2	329	193	9	563

[1] Includes municipal, state, and county entities.

[2] Includes only those industrials which make incidental deliveries to ultimate consumers.

[3] Data are from pool report which includes two investor owned systems.

supply are included in Chapter IV, Statement of Coordination. As shown on Figure 1 the coordination areas of these entities cover the entire region.

Systems in Power Pools

From the standpoint of reliability and coordination of operating matters each of the four large entities listed above constitutes an area of strong coordination. Each area is of sufficient size to provide adequate assistance during emergencies so that maximum advantage from this standpoint is achieved.

These four coordination areas include 17 larger systems along with a majority of the other systems which are basically distributors with their bulk power supply interests in the 17 larger systems. From a power supply standpoint, more than 97 percent of Region III's requirement is furnished from the bulk power systems of the TVA System, the Southern Company System, the Florida Group and the CARVA Pool.

Systems Not in Power Pools

Systems in the Southeast Region that are neither a principal to one of the four Regional Pools nor participants through contractual relations with their suppliers account for less than three percent of the energy supplied in Region III. The principal systems not in pools consist of South Carolina Public Service Authority, Alabama Electric Cooperative, Crisp County (Georgia), Key West, Gainesville, Fort Pierce, Tallahassee, Lakeland and 10 additional smaller isolated systems located in Florida. The isolated systems, 15 in all, account for only about 0.5 percent of the Region III energy. Some of these isolated systems are geographically remote making interconnection not feasible. Others find the costs of interconnections of sufficient capacity to fully integrate their systems with neighboring utilities unattractive.

Some additional potential for pool participation does exist but relative to Region III as a whole. this is small.

CHAPTER II

ESTIMATED FUTURE POWER REQUIREMENTS

General

The load estimates for the Southeast Region have been updated from the estimates used in the 1964 National Power Survey and extended for another 10 years to 1990. A comparison between the estimates for the Region in the 1964 Survey with estimates reported herein indicates about a 14 percent increase in the energy requirements for 1980.

The Southeast Regional Advisory Committee decided that the Southeast load studies should be approached by starting with individual studies made by the major power systems which in 1965 accounted for over 98 percent of the energy for load requirements in Region III. These systems are most familiar with the area in which they operate, its growth in industry and population, the degree to which electric heating and air conditioning is being used, and the extent of saturation of these uses. In preparing the studies each major system was requested to consider the various factors brought out in the "Guidelines for Revision and Extension of National Power Survey Load Forecast" as prepared and distributed by the Federal Power Commission. Special attention was given to electric heating for both commercial and residential customers, and other factors affecting the use of electricity such as price levels for competitive forms of energy. When the individual load forecasts were completed they were reviewed for possible overlaps, reasonableness of load factors, and the time of the year at which the system peaks occurred so that proper consideration could be given to diversity among the various systems. Separate consideration is being given in this report to existing diversity exchanges, including a large one with Region V, and to maintenance requirements. (See Chapter III.) An appropriate allowance was also made for smaller systems to grow in future years at a rate commensurate with that of the major systems.

All estimates are subject to changing conditions. With the present economic outlook these load forecasts should be reasonably accurate for 1970 and 1975 but in later years the projections will be subject to unknown influences and hence be less accurate. The projections for the period 1975–1990 are generally mathematical extrapolations based on historical patterns and short range forecasts tempered by the judgment of the individual systems. These longer range projections should be reviewed in future years and adjusted to new conditions, but should form a reasonable foundation for the development of transmission and generation patterns which will be needed to meet the future load requirements of the Southeast.

Annual Power Requirements

The total energy requirements in Region III in 1965 amounted to 203,145 gigawatt-hours with a coincidental peak load of 33.8 million kilowatts and a load factor of 68.6 percent. For 1990 these are projected as 1,204,580 gigawatt-hours, 210.4 million kilowatts, and 65.4 percent, respectively. This represents an energy growth by 1990 of nearly six times over 1965 and an average annual compound rate of growth of 7.6 percent over the period.

Table 2 summarizes for Region III and its component power supply areas past power requirements by 5-year intervals for the years 1955–1965 and estimated future requirements by 10-year intervals from 1970–1990. Table 3 shows the comparative growth of energy by various indices by power supply areas and for Region III.

Seasonal Characteristics

A considerable difference exists in the load patterns of utility systems in Region III owing to variations in temperature and weather conditions. In order to evaluate possible diversity savings and effect coordinated system planning it is necessary to have a knowledge of the various load patterns within the region. Table 4 shows estimated sum-

mer and winter peaks in Region III, each power supply area, and each of the power pools or coordinated study areas.

It will be noted from Table 4 that certain areas within the region experience summer peaks while others have winter peaks. Summer peaks are due in the main to air conditioning load as during extended hot periods the load builds up and is sustained for a relatively long time producing a fairly flat peak. In Areas 20 and 24 during low temperature periods the demands can cause annual peaks, but these peaks are normally not sustained as are the summer peaks. It will be noted from the table that in 1960 the region coincidental peak occurred in December, whereas in 1965 the August peak was slightly higher than the December peak. Projections for 1970 and 1980 indicate a winter peak, whereas by 1990 a shift is expected to a summer peak.

The summer peak season includes the months of June through September. Peaks are likely to occur during these months but most commonly occur in July or August. For study purposes, August is considered as the summer peak load month. Winter peak loads are likely to occur in the 5-month period November through March. For study purposes, December is the month selected for the winter peak load.

Tables 5 and 6 show estimated monthly peak demand and energy requirements for each of the 10-year intervals between 1970 and 1990. Also shown are actual monthly demands and energy data for the years 1960 and 1965. The tables reflect average patterns of recent years. In power supply areas where summer peaks have been in effect for some years the changes in monthly load characteristics occur gradually. In areas which are in the process of transition from a winter to a summer peak there will be a more marked change in load characteristics.

Principal Load Centers

Usually the development of power supply for an area is dependent upon the geographic dispersion of load. Utility customers are dispersed over the system in varying degrees of concentration. Load centers are points of load concentration. Where possible, system planning calls for location of generation and transmission facilities close to large load concentrations. Where conditions do not permit the location of generation close to load centers, backbone transmission must be provided to receive large blocks of power. Load centers in general conform to areas of large population concentrations and areas containing large industrial customers. While there is no exact way to determine power requirements of load centers, approximations can usually be made to indicate the area of future growth.

There are 71 load centers in Region III which are identified in Table 7. These load centers are expected to be 150 megawatts or larger by 1970. The table indicates the expected loads for the periods 1970, 1980, and 1990. The demands represent an allocation of the coincidental annual power supply area peaks, assuming no diversity among various load centers. Figure 2 shows the general areas of heavy load concentration in Region III. The shaded areas represent load concentrations of 1,000 megawatts or larger. Areas devoid of shading indicate more or less uniform dispersion of load in amounts less than the selected criterion.

Classified Sales

Total utility load is the summation of loads of various customer categories served. Since each type of load records its signature as a part of the total demand pattern, it becomes desirable to know what types of load and the amounts of each type being served. This knowledge makes it easier to analyze the requirements and supply data by each class of use. In addition, the data can be useful as an indicator of the identity of the probable future growth of each category.

Utilities have several types or categories, the major groups being defined as residential, rural, commercial, industrial, and "other." "Other" usually includes such services as street and highway lighting, water pumping, municipal services, such as schools and other municipal buildings and other significant amounts that may be identifiable by metering. The amount realized by summing up these categories represents energy sold for ultimate consumer use. The difference between this figure and the system energy for load is expressed as energy lost and unaccounted for. Rural consumption indicates energy used on the farm. The amount of energy requirements can vary greatly depending upon the type of farm served and the extent that labor saving devices are used. Residential use per customer would depend largely upon the satu-

ration of high energy use appliances, such as water heaters, ranges, air conditioners, heat pumps, and strip heating. Commercial customers are those that supply the services to the population of the area. These would include dry cleaning establishments, stores, theatres, filling stations, and the like. The industrial customer usually includes the large power consumers which are engaged in many industries such as processing of primary and non-ferrous metals, chemical production, and various types of mining. Some utilities rather than define the type of load by either manufacturing or service use the size and characteristic of the load served to establish the applicable rate charged. Similarly an agricultural operation, if large enough, might be classified under commercial or industrial category by virtue of the rate used in its classification.

Table 8 indicates actual distribution of sales by class of service for the 5-year periods 1955–1965 and, for the same interval, estimates of future distribution of sales between 1970 and 1990. In the past the categories experiencing the largest gains have been residential, commercial, and industrial. A large part of the industrial gain in Region III can be attributed to the Atomic Energy Commission's loads which have been curtailed in recent years but will no doubt come back into the picture within the next several years.

In 1965 Region III had energy for load of 203,145 gigawatt-hours. Of this total 59,069 gigawatt-hours or about 29.1 percent was classified as rural and residential sales. Of this amount about 90 percent or 53,129 gigawatt-hours was non-farm residential requirements, leaving 5,940 gigawatt-hours or about 10 percent for farm requirements. It is expected that the number of farms will continue to decrease and the average size farm will continue to increase in the future. By 1990 it is estimated that the farm requirements will increase to 16,612 gigawatt-hours and at that time will represent about seven percent of the rural and residential requirements.

By 1990 commercial sales are expected to increase to about 23 percent of the total load from about 14 percent in 1965. During this period the industrial load is expected to remain at about 46 percent of the total load.

Utility Load Curves

A useful tool in analyzing system load characteristics is the load curve. These curves are usually presented as load duration or integrated energy types and may present data on a daily, weekly, or monthly basis. Figures 3 and 4 show integrated hourly load curves for the peak day in the weeks of August and December. These curves are plotted for Power Supply Areas 22 and 23 separately and combined. The curves for the combined Areas represent the load pattern of The Southern Company System. The tabulation below shows the load characteristics for the week containing each day plotted:

	August 1965			December 1965		
	PSA 22	PSA 23	PSA 22 & 23	PSA 22	PSA 23	PSA 22 & 23
Coin. Peak (MW)	3, 419	3, 474	6, 893	2, 924	3, 487	6, 411
Energy (GWH)	445	430	875	372	426	798
Load Factor (%)	77. 4	73. 7	75. 6	75. 7	72. 7	74. 1

An examination of the curves shows that Power Supply Area 22 has a smaller variation between the maximum and minimum demand than that for Power Supply Area 23. The higher load factor for Power Supply Area 22 reflects this lower ratio between maximum and minimum demands. It will be noted that the peak hours are not sustained for as long an interval in the December curve as that for August. The broader summer peak reflects the sustained effects of relatively high cooling facility saturations.

Figure 5 shows the estimated load duration curve for The Southern Company System for the summer peak week in 1990. The curve has characteristics similar to a selected week in August of 1965. Allocation of the estimated 1990 power supply to positions on the curve illustrates how the various types of generating capacity could be utilized to serve the system load. In Figure 5 the conventional hydroelectric supply is loaded on the curve in the most advantageous position. Next the pumped-storage hydroelectric supply is loaded. The pumped-storage

supply is indicated in two bands above and below the position of the conventional hydroelectric supply. The nuclear supply is loaded in the base and the fossil-fuel supply is loaded to fill the curve. Shown above the peak is available supply expected in excess of load requirements. Power requirements associated with the operation of pumped-storage capacity are shown outside the duration curve.

TABLE 2

Region III—Past and Estimated Future Annual Power Requirements [1] [2]

PSA and region	Item	Unit	Actual			Estimated		
			1955	1960	1965	1970	1980	1990
18	Energy for Load	GWH	5, 938	9, 380	14, 994	23, 790	57, 420	114, 240
	Peak Demand	MW	[3] 1, 171	1, 815	2, 923	4, 770	11, 170	21, 760
	Load Factor	%	57. 9	58. 8	58. 6	56. 9	58. 7	59. 9
20	Energy for Load	GWH	53, 207	66, 520	77, 378	96, 720	185, 550	253, 160
	Peak Demand	MW	[3] 8, 314	[3] 10, 732	[3] 12, 804	[3] 18, 050	[3] 33, 610	[3] 47, 010
	Load Factor	%	73. 0	70. 6	69. 0	61. 2	63. 0	61. 5
21	Energy for Load	GWH	19, 560	27, 488	41, 374	66, 500	143, 650	313, 880
	Peak Demand	MW	[3] 3, 597	[3] 4, 992	7, 322	11, 460	24, 560	53, 300
	Load Factor	%	62. 1	62. 7	64. 5	66. 2	66. 8	67. 2
22	Energy for Load	GWH	8, 778	13, 458	20, 391	32, 180	67, 930	126, 890
	Peak Demand	MW	1, 640	2, 548	3, 896	6, 080	12, 940	23, 970
	Load Factor	%	61. 1	60. 1	59. 7	60. 4	59. 9	60. 4
23	Energy for Load	GWH	9, 068	13, 822	20, 916	33, 890	66, 150	137, 790
	Peak Demand	MW	1, 757	2, 638	3, 882	6, 320	12, 190	25, 260
	Load Factor	%	58. 9	59. 6	61. 5	61. 2	61. 9	62. 3
24	Energy for Load	GWH	8, 464	16, 843	28, 092	46, 060	115, 510	258, 620
	Peak Demand	MW	[3] 1, 833	[3] 3, 651	5, 274	[3] 9, 100	22, 020	50, 260
	Load Factor	%	52. 7	52. 5	60. 8	57. 8	59. 9	58. 7
Region III	Energy for Load	GWH	105, 015	147, 511	203, 145	299, 140	636, 210	1, 204, 580
	Peak Demand [4]	MW	[3] 18, 168	[3] 25, 947	33, 811	[3] 52, 960	[3] 109, 270	210, 400
	Load Factor	%	66. 0	64. 7	68. 6	64. 5	66. 5	65. 4

[1] AEC loads included in conformity with FPC guidelines.

[2] Loads do not reflect existing seasonal exchanges both within and without Region III nor the effect of other elements such as maintenance requirements. For separate treatment of diversity, see Chapter III.

[3] Winter peak, all others summer.

[4] Maximum seasonal load, see Table 4.

TABLE 3

Region III—Comparative Growth of Total Energy Requirements

PSA, region, and PSA groups	Index 1960=100						
	1960	1965	1970	1975	1980	1985	1990
18	100	160	254	403	612	883	1, 218
20	100	116	145	204	279	329	381
21	100	151	242	361	523	761	1, 142
22	100	152	239	353	505	720	943
23	100	151	245	325	479	695	997
24	100	167	273	440	686	1, 038	1, 535
Region III	100	138	203	298	431	595	816
18 and 21	100	153	245	372	545	792	1, 161
22 and 23	100	151	242	339	491	707	970

PSA, region, and PSA groups	Five Year Compound Rate of Annual Growth in Percent					
	1960–65	1965–70	1970–75	1975–80	1980–85	1985–90
18	9. 8	9. 7	9. 7	8. 7	7. 6	6. 6
20	3. 0	4. 6	7. 1	6. 5	3. 4	3. 0
21	8. 6	10. 0	8. 3	7. 7	7. 9	8. 5
22	8. 7	9. 6	8. 1	7. 4	7. 4	5. 5
23	8. 6	10. 1	5. 7	8. 0	7. 7	7. 4
24	10. 8	10. 4	10. 0	9. 3	8. 6	8. 1
Region III	6. 7	8. 0	8. 0	7. 7	6. 6	6. 5
18 and 21	8. 9	9. 8	8. 7	8. 0	7. 7	8. 0
22 and 23	8. 6	9. 8	7. 0	7. 7	7. 5	5. 7

TABLE 4

Region III—Past and Estimated Future Summer and Winter Peak Demands (Megawatts)

PSA, region, and PSA groups	1955				1960				1965			
	Summer		Winter		Summer		Winter		Summer		Winter	
18	1, 091	Aug.	1, 171	Dec.	1, 815	Aug.	1, 801	Dec.	2, 923	Sept.	2, 620	Dec.
20	7, 063	July	8, 314	Nov.	8, 551	Aug.	10, 732	Dec.	10, 618	Aug.	12, 804	Feb.
21	3, 453	Aug.	3, 597	Dec.	4, 990	Aug.	4, 992	Dec.	7, 322	Aug.	6, 945	Dec.
22	1. 640	Aug.	1, 547	Dec.	2, 548	July	2, 250	Dec.	3, 896	Aug.	3, 030	Dec.
23	1, 757	Aug.	1, 752	Dec.	2, 638	Aug.	2, 521	Dec.	3, 882	Aug.	3, 560	Dec.
24	1, 490	Sept.	1, 833	Dec.	3, 013	Sept.	3, 651	Dec.	5, 274	Sept.	4, 958	Dec.
Region III	16, 395	Aug.	18, 168	Dec.	23, 482	Aug.	25, 947	Dec.	33, 811	Aug.	33, 431	Dec.
18 and 21	4, 544	Aug.	4, 768	Dec.	6, 805	Aug.	6, 793	Dec.	10, 195	Aug.	9, 565	Dec.
22 and 23	3, 397	Aug.	3, 299	Dec.	5, 176	Aug.	4, 771	Dec.	7, 778	Aug.	6, 590	Dec.

PSA, region, and PSA groups	1970		1980		1990	
	Summer	Winter	Summer	Winter	Summer	Winter
18	4, 770	4, 060	11, 170	8, 340	21, 760	15, 780
20	14, 090	18, 050	26, 260	33, 610	35, 850	47, 010
21	11, 460	11, 070	24, 560	23, 180	53, 300	49, 360
22	6, 080	4, 970	12, 940	10, 810	23, 970	19, 950
23	6, 320	5, 710	12, 190	11, 340	25, 260	23, 460
24	8, 680	9, 100	22, 020	21, 990	50, 260	50, 090
Region III	51, 400	52, 960	109, 140	109, 270	210, 400	205, 650
18 and 21	16, 230	15, 130	35, 730	31, 520	75, 060	65, 140
22 and 23	12, 400	10, 680	25, 130	22, 150	49, 230	43, 410

NOTES.—1955–65 actual; 1970–90 estimated.

TABLE 5

Region III—Monthly Peak Demands (Megawatts)

PSA and Region	Year	January	February	March	April	May	June	July	August	September	October	November	December
18	1960	1,547	1,492	1,470	1,488	1,443	1,676	1,658	1,815	1,725	1,609	1,695	1,801
	1965	2,335	2,360	2,213	2,105	2,602	2,711	2,684	2,873	2,923	2,350	2,547	2,620
	1970	3,864	3,816	3,625	3,482	4,054	4,579	4,722	4,770	4,579	3,578	3,768	4,060
	1980	8,266	8,098	7,931	7,763	9,271	10,723	11,058	11,170	10,723	7,897	8,154	8,340
	1990	15,558	15,232	15,014	14,688	17,843	20,890	21,542	21,760	20,890	15,232	15,558	15,780
20	1960	10,002	9,983	10,065	8,886	8,672	8,390	8,411	8,551	8,478	9,032	9,682	10,732
	1965	12,345	12,804	11,808	10,286	9,680	10,098	10,185	10,618	10,220	10,830	12,260	12,318
	1970	17,671	16,714	16,046	14,386	12,978	13,754	14,602	14,729	14,079	14,639	16,426	18,050
	1980	33,610	31,593	30,417	27,359	24,771	26,216	27,896	28,165	26,922	26,854	30,249	33,240
	1990	47,010	43,954	42,262	37,843	34,176	36,151	38,689	39,065	37,279	36,527	41,463	45,788
21	1960	4,610	4,555	4,596	4,391	4,203	4,822	4,860	4,990	4,792	4,624	4,699	4,992
	1965	6,484	6,494	6,306	6,114	6,656	6,890	7,064	7,322	7,050	6,590	6,898	6,945
	1970	10,199	9,970	9,741	9,512	9,970	10,887	11,116	11,460	10,887	10,429	10,887	11,070
	1980	21,122	20,753	20,262	19,894	21,122	23,823	24,314	24,560	23,578	22,595	22,841	23,180
	1990	43,173	42,640	42,107	41,574	45,305	51,701	52,767	53,300	51,701	48,503	47,437	49,360
22	1960	2,041	2,000	2,036	2,029	2,250	2,487	2,548	2,538	2,508	2,135	2,116	2,250
	1965	2,803	2,887	2,773	2,846	3,414	3,617	3,780	3,896	3,762	3,118	2,976	3,030
	1970	4,560	4,408	4,256	4,378	5,168	5,776	5,898	6,080	5,837	5,046	4,864	4,970
	1980	9,705	9,382	9,058	9,317	10,999	12,293	12,552	12,940	12,422	10,740	10,299	10,810
	1990	17,978	17,378	16,779	17,258	20,375	22,772	23,251	23,970	23,011	19,895	19,176	19,950
23	1960	2,310	2,257	2,296	2,176	2,358	2,543	2,620	2,638	2,576	2,343	2,289	2,521
	1965	3,277	3,282	3,185	3,020	3,459	3,619	3,715	3,882	3,707	3,337	3,509	3,560
	1970	5,372	5,214	5,056	4,993	5,498	6,004	6,194	6,320	6,067	5,435	5,625	5,710
	1980	10,362	10,057	9,752	9,630	10,605	11,581	11,946	12,190	11,702	10,483	10,849	11,340
	1990	21,471	20,840	20,208	19,955	21,976	23,997	24,755	25,260	24,250	21,724	22,481	23,460
24	1960	3,266	3,097	2,908	2,743	2,831	2,820	2,948	2,950	3,013	2,995	2,966	3,651
	1965	5,116	4,622	4,634	4,633	4,615	4,664	4,909	5,220	5,274	5,123	4,685	4,958
	1970	8,736	8,281	7,735	7,462	7,690	7,917	8,145	8,345	8,680	8,008	7,735	9,100
	1980	21,139	20,038	19,157	18,056	18,497	19,312	20,214	20,985	22,020	20,258	19,488	21,990
	1990	47,998	45,737	43,726	41,213	42,218	44,229	46,239	48,551	50,260	46,239	44,480	50,090
III	1960	23,776	23,384	23,371	21,713	21,757	22,738	23,045	23,482	23,092	22,738	23,447	25,947
	1965	32,360	32,449	30,919	29,004	30,426	13,599	32,337	33,811	32,936	31,348	32,875	33,431
	1970	50,402	48,403	46,459	44,213	45,358	48,917	50,677	51,704	50,129	47,135	49,305	52,960
	1980	104,204	99,921	96,577	92,019	95,265	103,948	107,980	110,010	107,367	98,827	101,880	108,900
	1990	193,188	185,781	180,096	172,531	181,893	199,740	207,243	211,906	207,391	188,120	190,595	204,428

TABLE 6

Region III—Monthly and Annual Energy Requirements (Gigawatt-Hours)

PSA and region	Year	January	February	March	April	May	June	July	August	September	October	November	December	Annual energy GWH
18	1960	761	723	782	706	733	782	823	903	785	775	765	842	9, 380
	1965	1, 217	1, 112	1, 204	1, 107	1, 198	1, 253	1, 373	1, 440	1, 328	1, 223	1, 223	1, 316	14, 994
	1970	1, 970	1, 786	1, 853	1, 744	1, 856	2, 027	2, 229	2, 265	2, 043	1, 946	1, 951	2, 120	23, 790
	1980	4, 726	4, 284	4, 358	4, 094	4, 364	5, 036	5, 524	5, 610	5, 076	4, 582	4, 679	5, 087	57, 420
	1990	9, 345	8, 465	8, 442	7, 917	8, 454	10, 304	11, 276	11, 447	10, 384	8, 888	9, 253	10, 065	114, 240
20	1960	5, 987	5, 794	6, 273	5, 188	5, 242	4, 982	5, 228	5, 355	5, 082	5, 368	5, 628	6, 393	66, 520
	1965	7, 108	6, 497	7, 053	5, 880	5, 986	6, 019	6, 380	6, 441	5, 975	6, 289	6, 428	7, 322	77, 378
	1970	9, 237	8, 357	8, 095	7, 244	7, 138	7, 496	8, 066	8, 212	7, 496	7, 515	8, 366	9, 498	96, 720
	1980	17, 720	16, 310	15, 568	13, 972	13, 786	14, 491	15, 642	15, 902	14, 510	14, 120	15, 716	17, 813	185, 550
	1990	24, 506	21, 772	21, 316	19, 038	18, 759	19, 822	21, 492	21, 898	19, 873	18, 962	21, 367	24, 354	253, 160
21	1960	2, 312	2, 204	2, 361	2, 133	2, 238	2, 282	2, 254	2, 477	2, 284	2, 292	2, 251	2, 400	27, 488
	1965	3, 381	3, 119	3, 427	3, 176	3, 399	3, 425	3, 522	3, 778	3, 555	3, 472	3, 461	3, 659	41, 374
	1970	5, 586	5, 047	5, 353	5, 074	5, 406	5, 559	5, 726	6, 085	5, 659	5, 593	5, 553	5, 859	66, 500
	1980	12, 038	10, 860	11, 320	10, 716	11, 434	12, 282	12, 641	13, 431	12, 498	11, 851	11, 952	12, 627	143, 650
	1990	26, 209	23, 667	24, 232	22, 881	24, 483	27, 433	28, 218	29, 944	27, 904	25, 361	26, 052	27, 496	313, 880
22	1960	1, 063	993	1, 073	1, 013	1, 094	1, 218	1, 300	1, 322	1, 178	1, 086	1, 028	10, 90	13, 458
	1965	1, 537	1, 435	1, 556	1, 528	1, 746	1, 828	2, 017	2, 061	1, 870	1, 624	1, 553	1, 636	20, 391
	1970	2, 606	2, 381	2, 372	2, 327	2, 668	2, 812	3, 083	3, 192	2, 832	2, 565	2, 607	2, 735	32, 180
	1980	5, 570	5, 027	4, 823	4, 735	5, 454	6, 114	6, 691	6, 915	6, 161	5, 231	5, 435	5, 774	67, 930
	1990	10, 405	9, 390	8, 679	8, 502	9, 847	11, 750	12, 841	13, 246	11, 852	9, 441	10, 151	10, 786	126, 890
23	1960	1, 120	1, 071	1, 146	1, 046	1, 110	1, 169	1, 232	1, 295	1, 191	1, 149	1, 108	1, 185	13, 822
	1965	1, 666	1, 548	1, 672	1, 551	1, 729	1, 725	1, 893	1, 987	1, 841	1, 724	1, 721	1, 859	20, 916
	1970	2, 823	2, 538	2, 623	2, 474	2, 732	2, 908	3, 104	3, 236	2, 948	2, 762	2, 766	2, 976	33, 890
	1980	5, 556	5, 001	4, 948	4, 650	5, 160	5, 808	6, 185	6, 450	5, 881	5, 213	5, 444	5, 854	66, 150
	1990	11, 671	10, 513	9, 935	9, 328	10, 376	12, 373	13, 145	13, 710	12, 511	10, 500	11, 437	12, 291	137, 790
24	1960	1, 374	1, 299	1, 364	1, 309	1, 368	1, 415	1, 502	1, 553	1, 428	1, 415	1, 332	1, 484	16, 843
	1965	2, 178	1, 990	2, 231	2, 228	2, 297	2, 412	2, 536	2, 750	2, 622	2, 361	2, 171	2, 316	28, 092
	1970	3, 537	3, 192	3, 533	3, 482	3, 689	4, 210	4, 445	4, 652	4, 445	3, 768	3, 399	3, 708	46, 060
	1980	8, 432	7, 566	8, 733	8, 594	9, 125	10, 950	11, 805	12, 232	11, 817	9, 310	8, 086	8, 860	115, 510
	1990	17, 897	15, 957	19, 267	18, 957	20, 147	26, 198	27, 491	28, 655	27, 517	20, 560	17, 121	18, 853	258, 620
III	1960	12, 617	12, 084	12, 999	11, 395	11, 785	11, 848	12, 339	12, 905	11, 948	12, 085	12, 112	13, 394	147, 511
	1965	17, 087	15, 701	17, 143	15, 470	16, 355	16, 662	17, 721	18, 457	17, 191	16, 693	16, 557	18, 108	203, 145
	1970	25, 759	23, 301	23, 829	22, 345	23, 489	25, 012	26, 653	27, 642	25, 423	24, 149	24, 642	26, 896	299, 140
	1980	54, 042	49, 048	49, 750	46, 761	49, 323	54, 681	58, 488	60, 540	55, 943	50, 307	51, 312	56, 015	636, 210
	1990	100, 033	89, 764	91, 871	86, 623	92, 066	107, 880	114, 464	118, 900	110, 041	93, 712	95, 381	103, 845	1, 204, 508

TABLE 7

Region III—Estimated Peak Demands of Principal Load Centers [1] (Megawatts)

Load center	1970	1980	1990
Power Supply Area 18:			
Alexandria	1,087	2,545	4,958
Charlottesville	502	1,175	2,289
Richmond-Petersburg	1,215	2,845	5,542
Norfolk-Hampton	1,311	3,070	5,980
Chase City	192	450	877
Albemarle	463	1,085	2,114
Total Load Centers [2]	4,770	11,170	21,760
Total Power Supply Area [2]	4,770	11,170	21,760
Power Supply Area 20:			
West Point	404	752	1,052
Tupelo	357	665	930
Memphis	1,518	2,827	3,954
Martin	429	799	1,118
Paducah-Calvert City	1,600	2,090	2,510
Hopkinsville	449	836	1,169
Nashville	1,600	2,979	4,167
Columbia-Mt. Pleasant	1,911	3,558	4,977
McMinnville	293	546	764
Chattanooga	1,911	3,558	4,977
Oak Ridge-Knoxville	3,055	4,610	5,950
Johnson City	823	1,532	2,143
Wilson Dam	1,242	2,313	3,235
Huntsville	1,220	2,272	3,178
Total Load Centers [3]	16,812	29,337	40,124
Total Power Supply Area [3]	18,050	33,610	47,010
Power Supply Area 21:			
Greensboro	397	851	1,847
Winston-Salem	413	885	1,921
Salisbury	552	1,183	2,567
Charlotte-Gastonia	1,041	2,231	4,842
Hickory	385	825	1,790
Rutherfordton-Hendersonville	388	832	1,806
Asheville	346	742	1,610
Spartanburg	534	1,144	2,483
Greenville	664	1,423	3,088
Anderson	355	761	1,652
Lancaster	365	782	1,697
Columbia	273	585	1,270
Wilmington	463	992	2,153
Charleston	453	971	2,107
Burlington	201	431	935
Durham	223	478	1,037
Elkin	176	377	818
Raleigh	594	1,273	2,763
Fayetteville	625	1,339	2,906
Hartsville-Florence	541	1,159	2,515
Total Load Centers [2]	8,989	19,264	41,807
Total Power Supply Area [2]	11,460	24,560	53,300

See footnotes at end of table.

TABLE 7—Continued

Region III—Estimated Peak Demands of Principal Load Centers [1] (Megawatts)—Continued

Load center	1970	1980	1990
Power Supply Area 22:			
Gulfport	480	1, 022	1, 893
Mobile	842	1, 792	3, 319
Opp	200	426	789
Hattiesburg-Laurel	335	713	1, 321
Meridian	155	330	611
Pensacola	432	919	1, 702
Panama City	297	632	1, 171
Birmingham	1, 102	2, 345	4, 344
Gadsden-Anniston	422	898	1, 663
Talladega-Auburn	280	596	1, 104
Eufaula	199	424	785
Montgomery	328	698	1, 293
Tuscaloosa	185	394	730
Total Load Centers [2]	5, 257	11, 189	20, 725
Total Power Supply Area [2]	6, 080	12, 940	23, 970
Power Supply Area 23:			
Dalton-Rome	463	893	1, 850
Atlanta	1, 803	3, 478	7, 207
Macon	503	970	2, 010
Tifton	328	633	1, 312
Brunswick-Waycross	200	386	800
Savannah	289	557	1, 154
Columbus	280	540	1, 119
Augusta	500	964	1, 998
Total Load Centers [2]	4, 366	8, 421	17, 450
Total Power Supply Area [2]	6, 320	12, 190	25, 260
Power Supply Area 24:			
Jacksonville	814	1, 970	4, 496
Ocala	294	711	1, 623
Orlando	938	2, 270	5, 181
Canaveral	512	1, 239	2, 828
Bartow	816	1, 975	4, 508
St. Petersburg-Tampa	1, 680	4, 065	9, 278
Sarasota	342	828	1, 890
Riviera	533	1, 290	2, 944
Lauderdale	786	1, 902	4, 341
Miami	2, 102	3, 086	11, 609
Total Load Centers	[3] 8, 817	[2] 21, 336	[2] 48, 698
Total Power Supply Area	[3] 9, 100	[2] 22, 020	[2] 50, 260
Region III:			
Total Load Centers [4]	49, 011	100, 717	190, 564
Total Region [5]	55, 780	116, 490	221, 560

[1] Based on allocation of estimated coincidental power supply area peaks.
[2] Summer peak.
[3] Winter peak.
[4] Non-coincident.
[5] Non-coincident. Sum of power supply area peaks shown.

TABLE 8

Region III—Distribution of Electric Energy by Class of Use (Gigawatt-Hours)

PSA and region	Farm excluding irrigation and drainage pumping	Irrigation and drainage pumping	Nonfarm-residential	Commercial	Industrial	Street and highway lighting	Electrified transportation	All other	Total ultimate consumption	Losses	Energy for load
1955 Actual											
18	282	---	1,732	1,558	1,250	38	---	360	5,220	718	5,938
20	1,209	---	5,497	1,844	40,592	109	---	645	49,896	3,311	53,207
21	988	---	4,205	2,363	9,339	98	2	271	17,266	2,294	19,560
22	393	---	1,851	1,326	4,003	51	21	61	7,706	1,072	8,778
23	519	---	2,279	1,638	3,223	95	57	73	7,884	1,184	9,068
24	127	9	3,022	2,135	1,854	79	---	361	7,587	877	8,464
Region III	3,518	9	18,586	10,864	60,261	470	80	1,771	95,559	9,456	105,015
1960 Actual											
18	339	1	2,821	2,500	2,074	61	---	580	8,376	1,004	9,380
20	1,623	1	10,482	3,112	46,722	184	4	684	62,812	3,708	66,520
21	1,050	---	7,285	3,735	11,709	146	---	756	24,681	2,807	27,488
22	455	---	3,413	2,139	5,860	74	---	92	12,033	1,425	13,458
23	569	---	3,843	2,676	4,816	139	43	102	12,188	1,634	13,822
24	152	12	6,438	4,290	3,622	145	10	662	15,331	1,512	16,843
Region III	4,188	14	34,282	18,452	74,803	749	57	2,876	135,421	12,090	147,511
1965 Actual											
18	457	2	4,587	4,263	3,225	96	---	974	13,604	1,390	14,994
20	2,396	---	15,316	3,673	49,896	398	---	[1] 977	72,656	4,722	77,378
21	1,378	1	10,969	6,265	17,478	214	---	1,291	37,596	3,778	41,374
22	695	1	5,231	3,273	8,975	122	---	147	18,444	1,947	20,391
23	764	2	6,098	4,461	7,118	203	---	169	18,815	2,101	20,916
24	205	39	10,928	7,091	5,767	244	---	1,395	25,669	2,423	28,092
Region III	5,895	45	53,129	29,026	92,459	1,277	---	4,953	186,784	16,361	203,145
1970											
18	560	1	7,600	6,679	5,060	150	---	1,600	21,650	2,140	23,790
20	3,410	---	22,600	5,530	56,730	590	---	1,200	90,060	6,660	96,720
21	1,900	---	16,750	10,460	29,160	360	---	1,900	60,530	5,970	66,500
22	790	---	8,590	4,880	14,590	200	---	230	29,280	2,900	32,180
23	850	---	9,060	6,850	13,450	370	---	250	30,830	3,060	33,890
24	280	30	17,500	12,440	9,190	340	---	2,140	41,920	4,140	46,060
Region III	7,790	31	82,100	46,839	128,180	2,010	---	7,320	274,270	24,870	299,140
1975											
8	670	2	11,800	10,858	8,210	240	---	2,600	34,380	3,400	37,780
0	4,350	---	27,800	8,280	83,780	840	---	1,500	126,550	9,350	135,900
1	2,450	---	23,300	16,200	44,880	540	---	2,930	90,300	8,930	99,230
2	960	---	12,730	7,730	21,200	300	---	360	43,280	4,280	47,560
3	970	---	13,860	9,680	15,470	490	---	370	40,840	4,040	44,880
24	365	35	24,100	23,050	16,240	490	---	3,220	67,500	6,670	74,170
Region III	9,765	37	113,590	75,798	189,780	2,900	---	10,980	402,850	36,670	439,520
1980											
18	780	2	16,570	17,298	13,080	370	---	4,150	52,250	5,170	57,420
20	5,320	---	32,500	12,000	119,990	1,140	---	1,850	172,800	12,750	185,550
21	3,050	---	30,300	24,390	67,790	780	---	4,390	130,700	12,950	143,650
22	1,110	---	17,300	11,340	31,090	430	---	550	61,820	6,110	67,930
23	1,090	---	18,780	15,050	24,020	660	---	600	60,200	5,950	66,150
24	450	40	31,250	39,900	27,920	750	---	4,800	105,110	10,400	115,510
Region III	11,800	42	146,700	119,978	283,890	4,130	---	16,340	582,880	53,330	636,210
1985											
18	890	2	20,990	26,238	19,830	530	---	6,900	75,380	7,450	82,830
20	6,330	---	36,500	14,690	142,330	1,370	---	2,300	203,520	15,240	218,760
21	3,810	---	37,300	37,760	104,050	1,140	---	6,440	190,500	18,820	209,320
22	1,280	---	22,000	16,940	46,440	620	---	850	88,130	8,720	96,850
23	1,220	---	24,350	23,070	37,000	960	---	870	87,470	8,650	96,120
24	550	40	38,500	66,510	45,450	1,000	---	7,000	159,050	15,730	174,780
Region III	14,080	42	179,640	185,208	395,100	5,620	---	24,360	804,050	74,610	878,660

See footnote at end of table.

TABLE 8—Continued

Regional III—Distribution of Electric Energy by Class of Use (Gigawatt-Hours)—Continued

PSA and region	Farm excluding irrigation and drainage pumping	Irrigation and drainage pumping	Nonfarm-residential	Commer-cial	Industrial	Street and highway lighting	Electrified transpor-tation	All other	Total ultimate consump-tion	Losses	Energy for lead
					1990						
18	1,000	2	25,040	37,378	28,310	730		11,500	103,960	10,280	114,240
20	7,200		39,400	17,720	166,560	1,610		2,850	235,340	17,820	253,160
21	4,860		44,700	59,450	165,170	1,710		9,710	285,600	28,280	313,880
22	1,450		26,000	22,970	62,920	800		1,330	115,470	11,420	126,890
23	1,390		30,040	35,120	56,060	1,400		1,380	125,390	12,400	137,790
24	660	50	45,800	106,700	70,880	1,250		10,000	235,340	23,280	258,620
Region III	16,560	52	210,980	279,338	549,900	7,500		36,770	1,101,100	103,480	1,204,580

[1] Includes chemical operations at Wilson Dam.

SOUTHEAST REGIONAL ADVISORY COMMITTEE
REGION III
AREAS OF LOAD CONCENTRATION

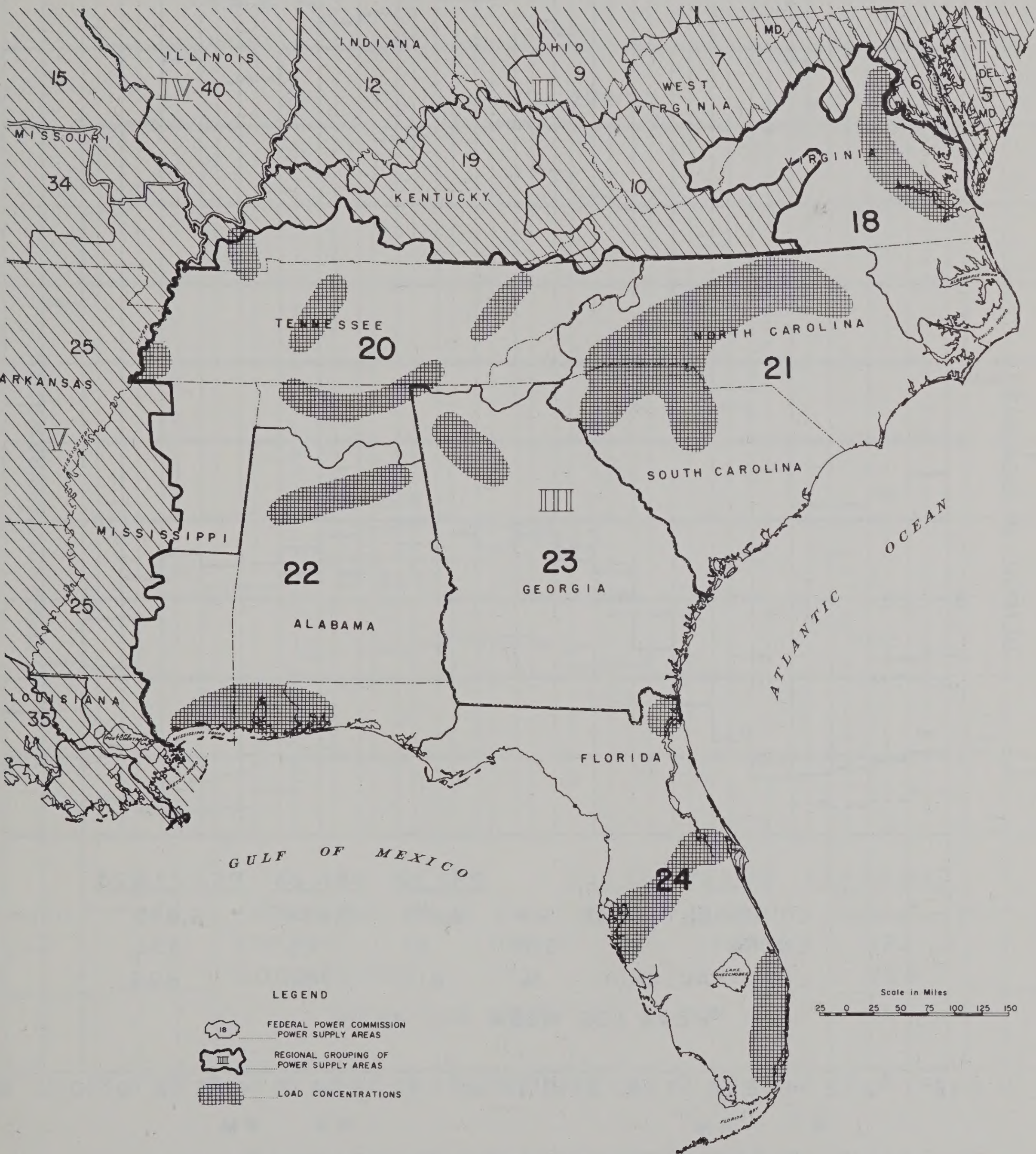

Figure 2

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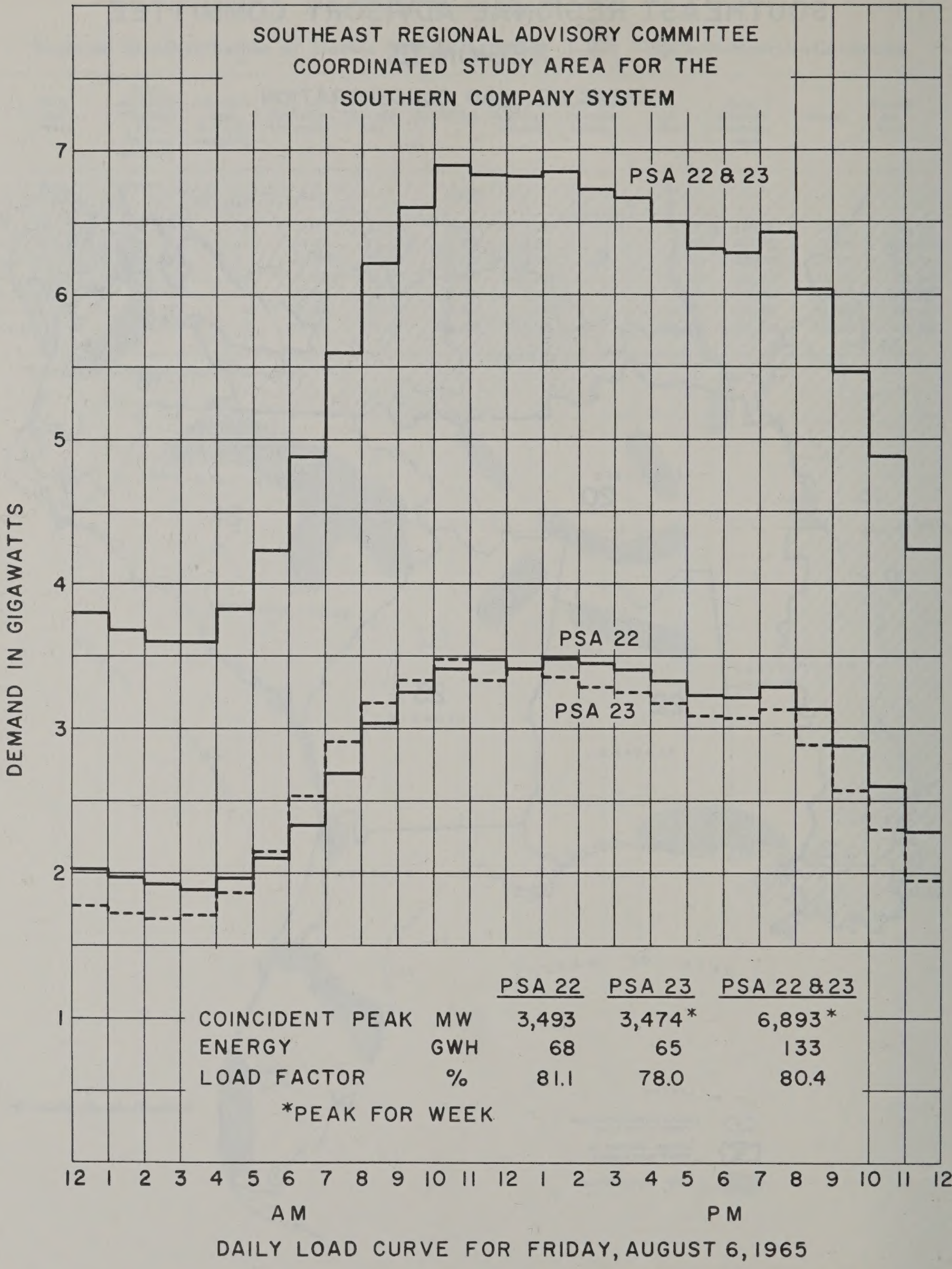

SOUTHEAST REGIONAL ADVISORY COMMITTEE
COORDINATED STUDY AREA FOR THE
SOUTHERN COMPANY SYSTEM
PSA 22 & 23
PSA 22
PSA 23
DEMAND IN GIGAWATTS
PSA 22 PSA 23 PSA 22 & 23
COINCIDENT PEAK MW 3,493 3,474* 6,893*
ENERGY GWH 68 65 133
LOAD FACTOR % 81.1 78.0 80.4
*PEAK FOR WEEK
12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12
AM
PM
DAILY LOAD CURVE FOR FRIDAY, AUGUST 6, 1965

Figure 3

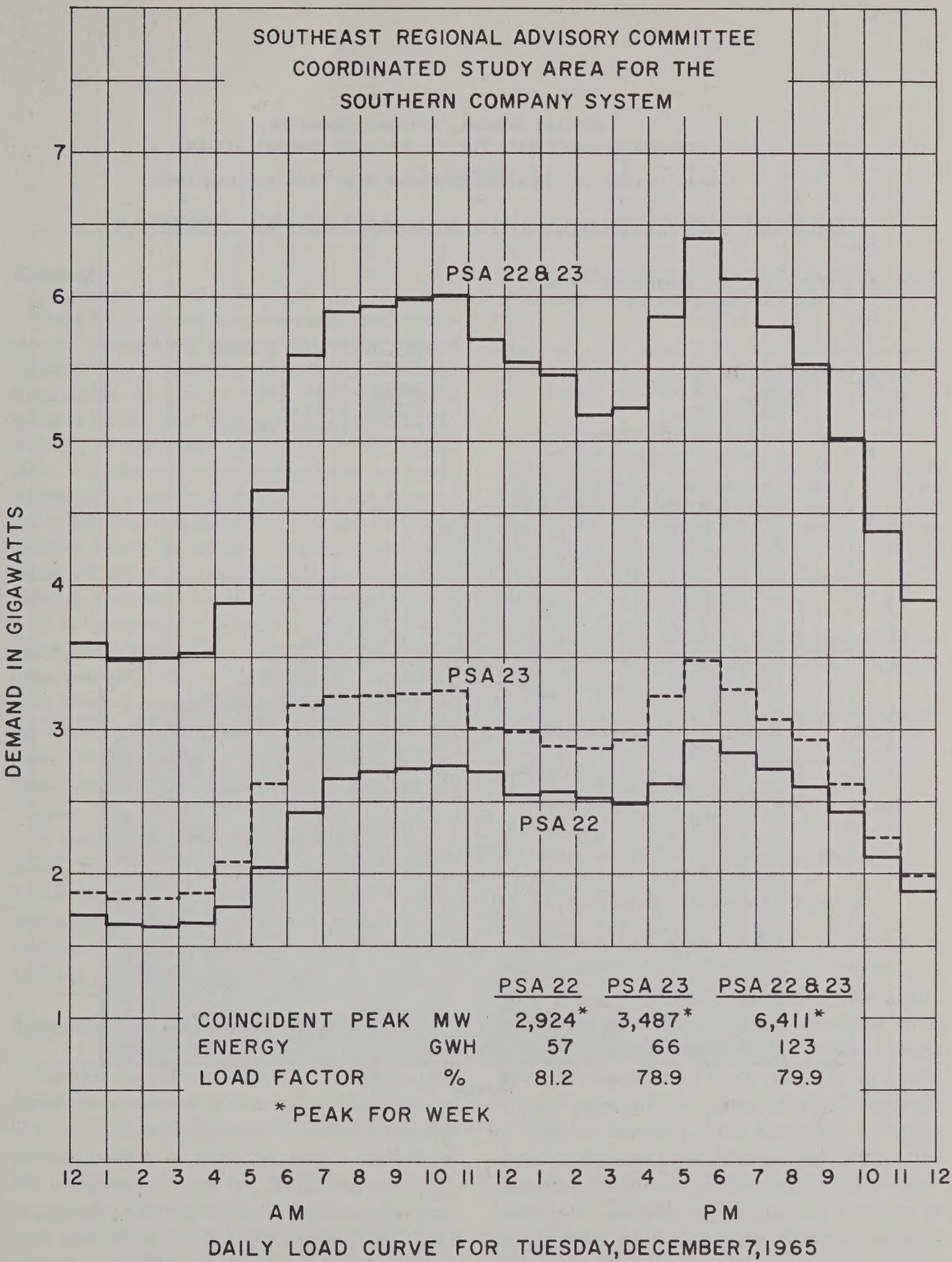

SOUTHEAST REGIONAL ADVISORY COMMITTEE
COORDINATED STUDY AREA FOR THE
SOUTHERN COMPANY SYSTEM
PSA 22 & 23
PSA 23
PSA 22
DEMAND IN GIGAWATTS
7
6
5
4
3
2
1
PSA 22 PSA 23 PSA 22 & 23
COINCIDENT PEAK MW 2,924* 3,487* 6,411*
ENERGY GWH 57 66 123
LOAD FACTOR % 81.2 78.9 79.9
* PEAK FOR WEEK
12 1 2 3 4 5 6 7 8 9 10 11 12 1 2 3 4 5 6 7 8 9 10 11 12
AM
PM
DAILY LOAD CURVE FOR TUESDAY, DECEMBER 7, 1965

Figure 4

SOUTHEAST REGIONAL ADVISORY COMMITTEE
COORDINATED STUDY AREA FOR THE SOUTHERN COMPANY SYSTEM

TYPICAL LOADING OF ESTIMATED 1990 PEAK WEEK LOAD DURATION CURVE

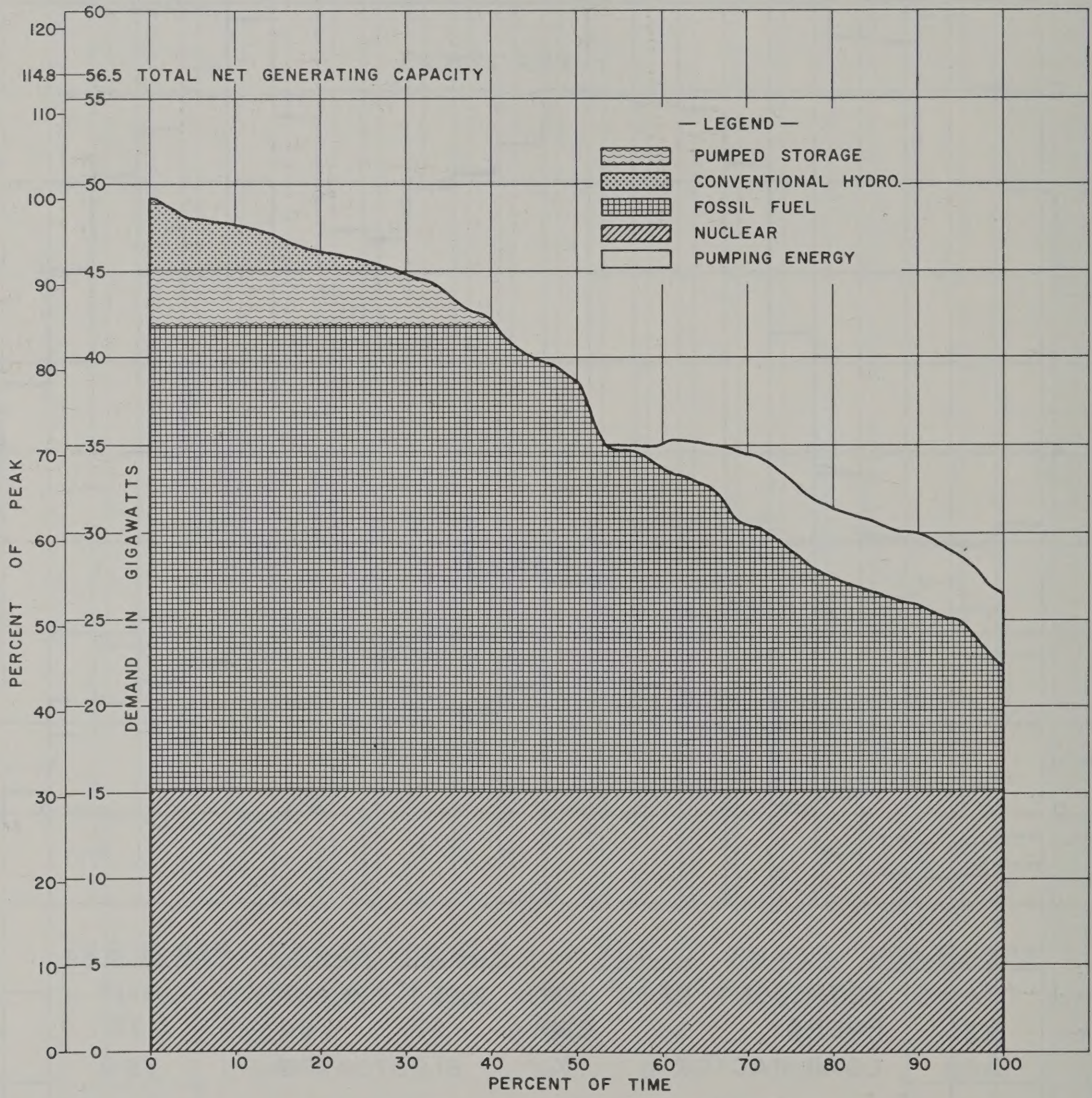


Figure 5

CHAPTER III

PATTERNS OF GENERATION AND TRANSMISSION 1970–90

General

The FPC Southeast Regional Advisory Committee has surveyed the plans of 25 utilities located within Region III for expansion of generation and transmission by periods, these additions being grouped by the years 1968 to 1970, inclusive; 1971 to 1975; 1976 to 1980; 1981 to 1985; and 1986 to 1990. In addition to plans for generation and transmission, the Committee has surveyed the status of and plans for coordination of bulk power supply facilities among the utilities, including current and future utilization of load diversity, as a means of reducing generating capacity requirements.

In this chapter, the Committee has made use of information collected for Chapter II, Future Power Requirements; Chapter V, Appraisal of Undeveloped Hydroelectric Potential in the Southeast; and the Report on Fuel Resources, Requirements and Costs For Electric Generation In Eastern United States which is summarized for the Southeast in Chapter VI.

In general, the patterns of generation and transmission are those developed by each of the major coordination areas within the region. These patterns generally have taken into account existing power contracts both within and between the areas. Beyond 1975 the patterns must be considered tentative.

Expansion of Generating Capacity

Plans for the addition of generating units by time periods were reported by each utility. Maps, Figures 6, 7, and 8, show the location of electric generating stations, existing or projected, with a capacity of 500 megawatts or more for 1970, 1980, and 1990, respectively. Generating station names and peak hour capabilities are included in the "Plant List" on each map. The type, kind, and size of units are deemed appropriate to meet the peak hour and energy loads detailed in Chapter II, Estimated Future Power Requirements. These loads are summarized below for ready reference:

Year	Energy (GWH)	Summer peak (MW)	Winter peak (MW)
1970	299, 140	51, 400	52, 960
1975	439, 520	75, 380	76, 690
1980	636, 210	109, 140	109, 270
1985	878, 660	152, 230	150, 360
1990	1, 204, 580	210, 400	205, 650

For the Region, the generating capacity additions contemplated to serve the foregoing loads are summarized as shown:

Period	*Added Capacity (MW)*
1968–70	13, 027
1971–75	31, 451
1976–80	37, 580
1981–85	49, 429
1986–90	62, 041

Types of Generating Capacity

Details of available hydroelectric generating resources are covered in Chapter V, Appraisal of Undeveloped Hydroelectric Potential in the Southeast. In the foregoing table, the conventional hydro capacity additions forecast by the utilities amount to 2,198 megawatts by 1990, compared to a total of 4,614 megawatts for plants rated 100 megawatts or larger as identified in the Appraisal. (Including capacity of plants rated 50 megawatts or more, the Appraisal identified a possible total of 6,970 megawatts.) In addition, the systems are planning to install about 8,500 megawatts of pumped-storage hydro capacity for peaking purposes. Nuclear power is expected to account for 38 to 50 percent of the generating capacity additions through 1980, and

36 to 59 percent by 1990.[1] It is noted that 16,000 to 18,000 megawatts of nuclear capacity have already been committed for operation through the year 1975.

Fossil-fired steam plants are expected to account for 42 to 31 percent of the added generating capacity through 1980, and 35 to 21 percent through 1990.[1] Power system annual load factors may be expected to range from 50 to 70 percent. In view of the relative operating costs of nuclear and fossil-fired steam-electric generating units, the former are primarily suitable for base load operation at capacity factors higher than system load factors. Also, generating capacity capable of operating economically at capacity factors somewhat below system load factors will be needed.

Unit Sizes

There is considerable variation in the size of generating units expected to be installed in the Southeast because differing load and area characteristics require different approaches by the utilities to achieve the lowest over-all cost consistent with a high degree of reliability. In many instances, coordination among adjacent utilities has resulted in the installation of larger generating units than would otherwise have been appropriate. Generating units planned for the CARVA Pool are an example. This practice can be expected to continue and to become even more widespread when economic benefits can be demonstrated. In this respect, an important consideration is the reliability of very large-sized generating units, especially during their early years of life. In the United States, experience so far indicates that the forced-outage rates of many large units have not declined with age or design maturity as rapidly as had been expected. This has required generating reserves to be maintained at a level somewhat higher than would have otherwise been necessary. In spite of this disadvantage, many large units have been installed to take advantage of lower unit investment and operating costs, and units as large as 1,275 megawatts are on order for Region III. The maximum and average sizes of fossil-fired and nuclear turbo-generating unit additions for the various time periods are as follows:

Period	Fossil unit size—MW		Nuclear unit size—MW	
	Maximum	Average	Maximum	Average
1968–70....	1, 130	447	1, 065	842
1971–75....	1, 275	515	1, 200	874
1976–80....	1, 200	615	1, 200	948
1981–85....	1, 250	698	2, 000	1, 076
1986–90....	1, 500	744	2, 000	1, 181

Peaking Capacity

Generation for peaking capacity is expected to come largely from hydroelectric installations, and especially from pumped-storage plants. Except for Florida, the terrain of much of the Region is generally suitable for hydro and pumped-storage installations. Nevertheless, a total of 993 megawatts of thermal peaking capacity is predicted by 1990, of which 490 megawatts will be located in Florida. Part of the motivation for such installations is the quick starting and "black start" capabilities of combustion turbines.

As discussed later, there may be a decrease in the need for energy-limited peaking capacity because it appears that summer peak loads will be controlling for Region III. These "peaks" extend with little reduction over some 6 to 12 hours per day. Because of the relatively high load factor operation required of peaking capacity under these summer load conditions, conventional hydro installations become increasingly less attractive and in many instances will be uneconomical when compared with thermal or pumped-storage peaking capacity.

Because of the short hours' use of hydro peaking capacity, the cost of transmitting such peaking capacity substantial distances is very great. This limits the effective radius of usefulness of a hydro peaking installation, and in many cases will make thermal peaking capacity more attractive.

Environmental Consideration

Utility Managements of the Southeast Region are deeply committed to making their power facilities compatible with the environmental quality needed for public health and enoyment. In connection with power generation, considerable attention is being given to air pollution and thermal effects on cooling water, as well as aesthetics, through studies and research, and by actual construction of costly facilities, the only purpose of which is to alleviate unde-

[1] A substantial number of future capacity additions were reported as "undecided" between fossil and nuclear units. The first figure is based on all "undecided" units being fossil and the second figure on all such units being nuclear.

sirable environmental effects. These include high efficiency electrostatic precipitators on new and old units, trial installations of sulphurdioxide removal systems on coal-fired boilers, construction of tall stacks, cooling towers, skimmer walls, cooling ponds, and other things. Active research is under way to determine the biological effects of warm water discharges on the ecology of various types of water bodies, as well as to determine and verify the mechanics of heat exchange to the environment and thereby aid in finding the ultimate generation potential of new power station sites.

Today, many Southeast utilities have a full-time environmental staff, the sole responsibility of which is to determine the compatibility of new facilities with their surroundings and evaluate the effects of existing facilities and determine what can be done to make them more compatible.

The concern of the general public for preservation of the quality of natural resources and environment is shared by the Southeast utilities. There is, however, much to be learned about such things as the effects of stack emissions on health and the effects of temperature change on the total ecology of our water bodies. The temperature change actually may be beneficial to marine life and recreation. The temperature effects in the Southeast Region will not necessarily be the same as those in other regions of the United States. There is concern that legislating excessively restrictive limits on stack emissions or condenser water temperature, based in part on emotions and on less than adequately demonstrated scientific or engineering facts, may result in unwarranted expenditures and may not be in the overall public interest. Further, such legislation could result in taking the wrong road in efforts to handle the problems of the future on a "crash" basis. For example, installation of large cooling towers may create problems from consumptive use of water, ground fogs, or general aesthetic objections.

Emphasis is on controlling within reasonable limits the effluents from facilities to make these facilities as compatible with the environment as possible within the limits of presently available technology—meanwhile putting forth vigorous research effort to obtain the facts on what is really required. Further research on an accelerated basis is needed and is being planned by the Southeast utilities. If the facts indicate the requirement for more stringent limits on effluents, they will be met insofar as is technically and economically feasible.

The rapid load growth expected in the Southeast makes it imperative that early solutions be found to the problems of best use of environment and natural resources for power production, while protecting them for public health and enjoyment.

Seasonal Diversities as Capacity Sources

Diversities of all types, and especially seasonal diversity, have been explored in the Southeast for the last decade. Random diversity has been shown to be undependable, but certain seasonal diversities have been found valuable. In 1962 two arrangements were formalized, one between Florida Power Corporation and the Southern system for a seasonal exchange of 100 megawatts, and the other between Tennessee Valley Authority and the South Central Electric Companies (Region V) for a seasonal exchange of 1,500 megawatts. Subsequent formal seasonal exchanges include 100 megawatts between Duke and Southern, and up to 300 megawatts between TVA and Southern.

One misconception of seasonal diversity exchange is that its potential is to be measured by taking the sum of the individual peaks whenever they occur and subtracting therefrom the summation of the winter peaks or the summer peaks, whichever is greater.

The existence of a substantial amount of hydro capacity in the Southeast must be carefully considered in any analysis of usable, seasonal load diversity. In many installations this capacity has been sized to offset the seasonal variation in the owning company's load. In other installations energy limitations may require that the capacity be reduced when dedicated to the load shape of a neighboring company. An equally important factor is the requirement that reserves be maintained at a level adequate for performing necessary maintenance. In this connection, means have been developed for estimating the type and amount of seasonal exchange capacity which a system may have available for exchange with others provided the opposite exchange is also available. These are illustrated in Appendix A.

While the 1964 National Power Survey predicted rather enormous seasonal capacity exchanges associated with Florida, developments in recent years have shown that the present small amount of winter peaking load which could be used as an offset to a system with a summer peaking load is actually decreasing, and beyond 1970 there will be no sub-

stantial amounts of seasonal capacity which could be exchanged outside of Florida. Actually, most of the entities in Florida will have either an approximate balance between summer and winter peaks, or will have summer peaking characteristics.

Examination of Appendix A shows that the principal opportunities for additional seasonal exchange in the Southeast in later years will be between the winter peaking TVA system and summer peaking systems.

Although a substantial portion of Region III operates on Eastern time and the remainder on Central time, there is relatively little "time-zone diversity" which can be utilized on a reliable basis. Weather extremes, which make loads unusually high, are likely to be spread across the entire Region and effectively cancel any "time-zone" or random diversity which might otherwise appear to be available.

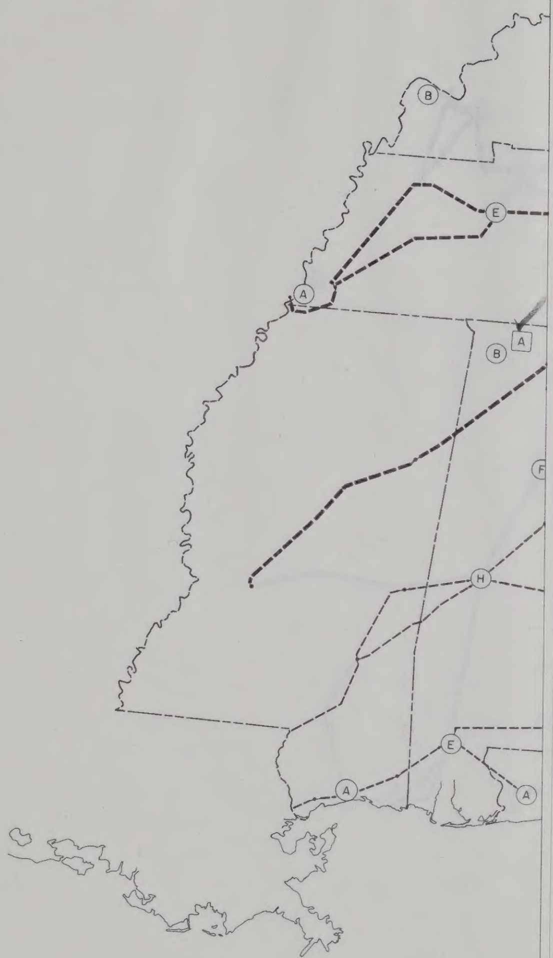
Appendix A includes detailed analyses of seasonal exchange potential of CARVA, peninsular Florida, Southern, and TVA, and these together represent the bulk of any exchange potential. It will be noted that maintenance requirements preclude seasonal exchanges of peninsular Florida or CARVA for the entire time period considered. This means that opportunities for seasonal exchange not already implemented or scheduled consist of possible summer capacity from TVA of some 193 megawatts in the 1980–81 period, some 580 megawatts in the 1985–86 period, and about 1,000 megawatts in the 1990–91 period. Comparison of these with the analysis of the Southern System which would have some small excess of winter capacity shows that further exchange of something under 200 megawatts may be feasible in 1980, perhaps some 200 megawatts in 1985, and some 300 megawatts in 1990. On this basis, some 700 megawatts summer capacity might be available in 1990. These amounts in the earlier years are so small and the conditions for the later years so uncertain that little, if any, transmission for seasonal exchange purposes alone can be justified.

Transmission Patterns

Much of the existing transmission in Region III is at 115 kilovolts, with a substantial block of 161-kilovolt lines in TVA and nearby Southern System connections. Substantial amounts of 230-kilovolt transmission have been built in most sections except in TVA's 161-kilovolt and 500-kilovolt areas. There are two notable installations of 500-kilovolt transmission, one designed, among other things, to accomplish seasonal diversity exchange between TVA and the South Central Electric Companies. The other is the 500-kilovolt transmission system from Virginia Electric and Power Company's mine-mouth Mt. Storm Plant. Short sections of 500-kilovolt line are being built in North Georgia. In addition, Duke Power Company, Carolina Power & Light Company, Virginia Electric and Power Company, and TVA plan extensive 500-kilovolt overlays of their existing transmission systems.

Within Region III opportunities for mine-mouth steam-electric generating stations are limited. Mt. Storm and some areas in western Kentucky offer such opportunity. In contrast, coal mining in Alabama involves thin seams so that there may be only a moderate cost difference between locally mined coal and Kentucky coal shipped by unit train.

The capability of a single 230-kilovolt line is about 300 to 500 megawatts, depending on the length of line, type, size, and configuration of conductor. A typical 500-kilovolt line has a capacity of 1,500 to 2,000 megawatts, depending upon the same limiting factors. Therefore, the selection of transmission voltage will hinge largely on the size of generating units and plants. Because steam-plant sites are reasonably plentiful in certain areas of Region III, plants can be located relatively close to major load centers. This factor currently tends to favor 230-kilovolt transmission as being more economical than 500 kilovolts in those areas. In other areas, conditions are substantially different. Load and population density, higher fossil-fuel costs, and a relatively poorer inventory of steam-plant sites have indicated the development of large plants and large unit sizes. For the entire Region substantial amounts of 500-kilovolt transmission are forecast, amounting to 4,150 miles by 1980 and 9,019 miles by 1990. The maps, Figures 6, 7, and 8, show the general location of future high-voltage lines forecast for 1970, 1980, and 1990, respectively. The existence of transmission voltages higher than 500 kilovolts is recognized, and interest is maintained in current developments at 765 kilovolts. It is of historical significance and interest that the use of 500 kilovolts in this country had its beginning in this Region. Even with the present rate of load growth, one could expect that, because of the factors noted above, i.e., relatively intermediate distances between load and generation, the 500-kilovolt system is expected to suffice through the 1980's. The Region will continue to show interest



PLANT LIST

1970

Alabama

Plant Name and Symbol	Net Peak Hour Capability, MW
A Wilson	620
B Colbert	1,282
C Widows Creek	1,871
D Browns Ferry	1,065
E Barry	892
F Gorgas	704
G Gaston	1,024
H Greene County	554

Florida

Plant Name and Symbol	Net Peak Hour Capability, MW
A Crist	577
B Crystal River	897
C Turkey Point	822
D Port Everglades	1,241
E Riviera	694
F Cape Kennedy	822
G Fort Myers	556
H Gannon	1,373
I Jacksonville	470

Georgia

Plant Name and Symbol	Net Peak Hour Capability, MW
A Harllee Branch	1,583
B Hammond	823
C McDonough	511
D Yates	621

Kentucky

Plant Name and Symbol	Net Peak Hour Capability, MW
A Paradise	2,560
B Shawnee	1,624

Mississippi

Plant Name and Symbol	Net Peak Hour Capability, MW
A J. Watson	571

North Carolina

Plant Name and Symbol	Net Peak Hour Capability, MW
A Roxboro	1,069
B Riverbend	665
C Allen	1,183
D Marshall	2,136

South Carolina

Plant Name and Symbol	Net Peak Hour Capability, MW
A Robinson	882

Tennessee

Plant Name and Symbol	Net Peak Hour Capability, MW
A Allen	930
B Bull Run	950
C Gallatin	1,208
D John Sevier	840
E Johnsonville	1,432
F Kingston	1,726

Virginia

Plant Name and Symbol	Net Peak Hour Capability, MW
A Chesterfield	1,397
B Portsmouth	788
C Possum Point	566

West Virginia

Plant Name and Symbol	Net Peak Hour Capability, MW
A Mt. Storm	1,124

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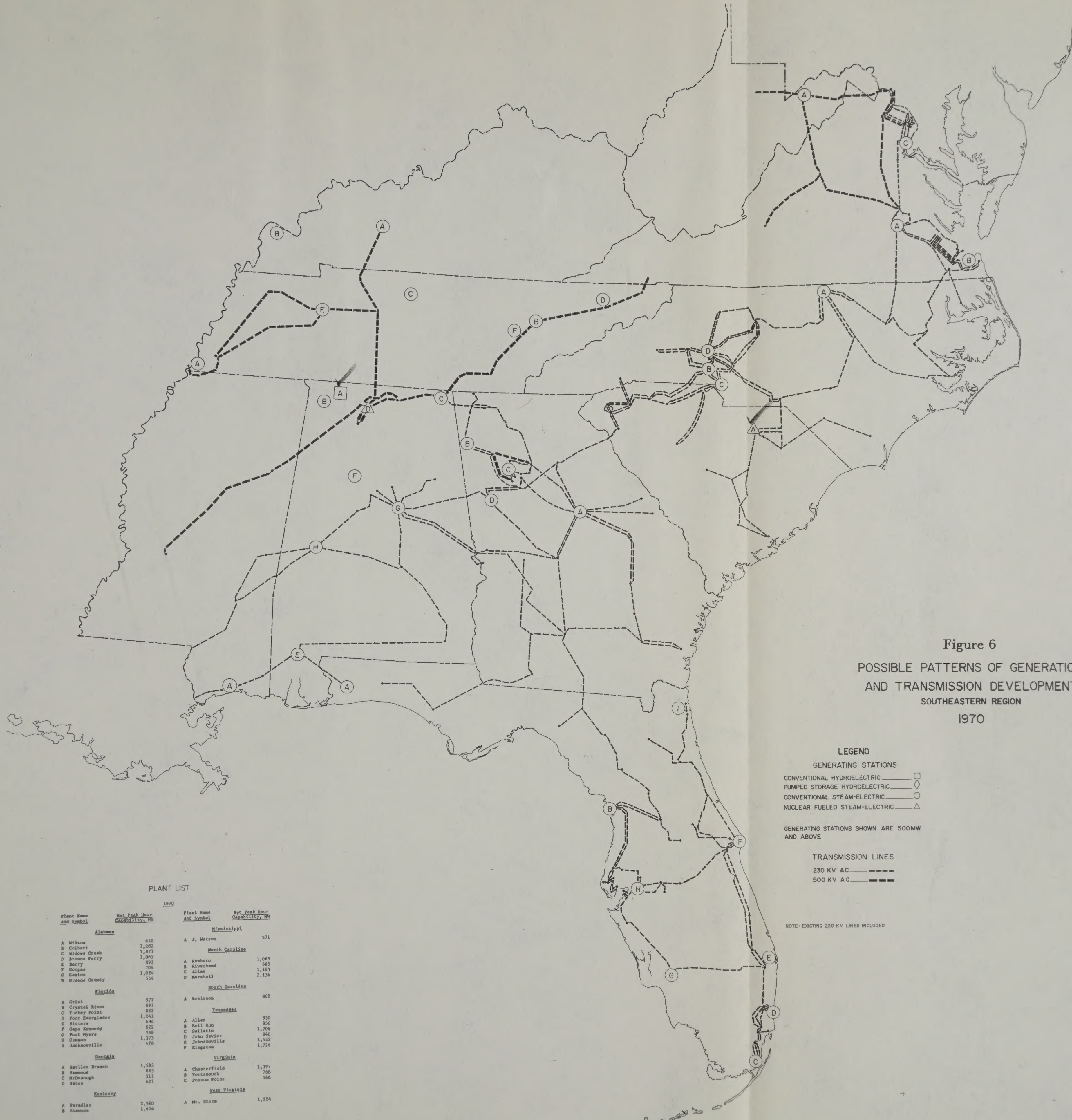

Figure 6
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SOUTHEASTERN REGION
1970

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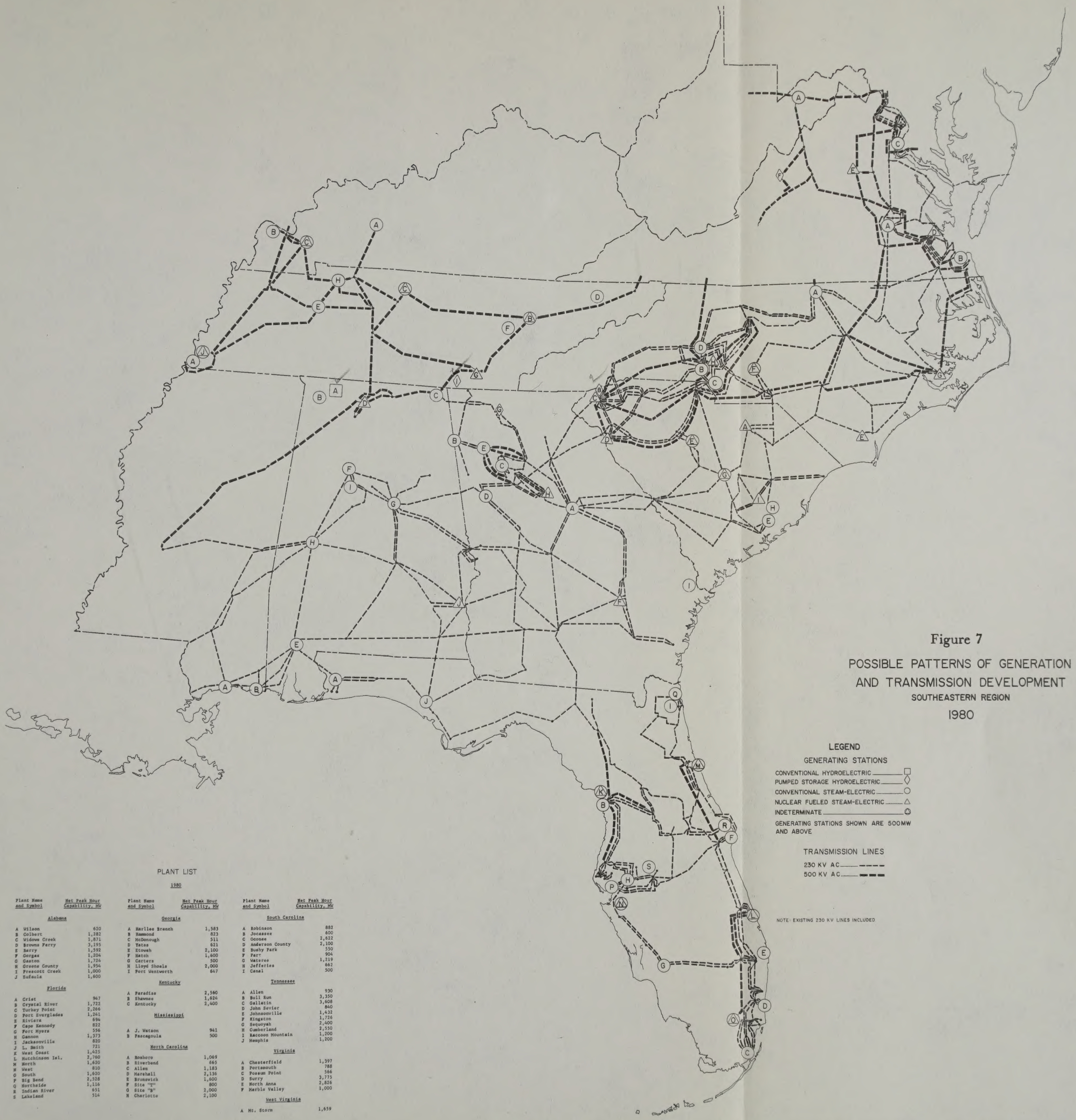

Figure 7

POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION DEVELOPMENT

SOUTHEASTERN REGION

1980

LEGEND

GENERATING STATIONS

CONVENTIONAL HYDROELECTRIC
PUMPED STORAGE HYDROELECTRIC
CONVENTIONAL STEAM-ELECTRIC
NUCLEAR FUELED STEAM-ELECTRIC
INDETERMINATE

GENERATING STATIONS SHOWN ARE 500MW AND ABOVE

TRANSMISSION LINES

230 KV AC
500 KV AC

NOTE: EXISTING 230 KV LINES INCLUDED

PLANT LIST

1980

Plant Name and Symbol		Net Peak Hour Capability, MW
	Alabama	
A	Wilson	620
B	Colbert	1,282
C	Widows Creek	1,871
D	Browns Ferry	3,195
E	Barry	1,592
F	Gorgas	1,204
G	Gaston	1,724
H	Greene County	1,954
I	Prescott Creek	1,000
J	Eufaula	1,600
	Florida	
A	Crist	947
B	Crystal River	1,722
C	Turkey Point	2,266
D	Port Everglades	1,241
E	Riviera	694
F	Cape Kennedy	822
G	Fort Myers	556
H	Gannon	1,373
I	Jacksonville	820
J	L. Smith	721
K	West Coast	1,425
L	Hutchinson Isl.	2,760
M	North	1,620
N	West	810
O	South	1,620
P	Big Bend	2,328
Q	Northside	1,116
R	Indian River	651
S	Lakeland	514

Plant Name and Symbol		Net Peak Hour Capability, MW
	Georgia	
A	Harllee Branch	1,583
B	Hammond	823
C	McDonough	511
D	Yates	621
E	Etowah	2,100
F	Hatch	1,600
G	Carters	500
H	Lloyd Shoals	2,000
I	Port Wentworth	647
	Kentucky	
A	Paradise	2,560
B	Shawnee	1,624
C	Kentucky	2,400
	Mississippi	
A	J. Watson	941
B	Pascagoula	500
	North Carolina	
A	Roxboro	1,069
B	Riverbend	665
C	Allen	1,183
D	Marshall	2,136
E	Brunswick	1,600
F	Site "T"	800
G	Site "B"	2,000
H	Charlotte	2,100

Plant Name and Symbol		Net Peak Hour Capability, MW
	South Carolina	
A	Robinson	882
B	Jocassee	600
C	Oconee	2,622
D	Anderson County	2,100
E	Bushy Park	550
F	Parr	904
G	Wateree	1,219
H	Jefferies	662
I	Canal	500
	Tennessee	
A	Allen	930
B	Bull Run	3,350
C	Gallatin	3,608
D	John Sevier	840
E	Johnsonville	1,432
F	Kingston	1,726
G	Sequoyah	2,400
H	Cumberland	2,550
I	Raccoon Mountain	1,200
J	Memphis	1,200
	Virginia	
A	Chesterfield	1,397
B	Portsmouth	788
C	Possum Point	566
D	Surry	3,775
E	North Anna	2,826
F	Marble Valley	1,000
	West Virginia	
A	Mt. Storm	1,659

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stantial amounts of seasonal capacity which could be exchanged outside of Florida. Actually, most of the entities in Florida will have either an approximate balance between summer and winter peaks, or will have summer peaking characteristics.

Examination of Appendix A shows that the principal opportunities for additional seasonal exchange in the Southeast in later years will be between the winter peaking TVA system and summer peaking systems.

Although a substantial portion of Region III operates on Eastern time and the remainder on Central time, there is relatively little "time-zone diversity" which can be utilized on a reliable basis. Weather extremes, which make loads unusually high, are likely to be spread across the entire Region and effectively cancel any "time-zone" or random diversity which might otherwise appear to be available.

Appendix A includes detailed analyses of seasonal exchange potential of CARVA, peninsular Florida, Southern, and TVA, and these together represent the bulk of any exchange potential. It will be noted that maintenance requirements preclude seasonal exchanges of peninsular Florida or CARVA for the entire time period considered. This means that opportunities for seasonal exchange not already implemented or scheduled consist of possible summer capacity from TVA of some 193 megawatts in the 1980–81 period, some 580 megawatts in the 1985–86 period, and about 1,000 megawatts in the 1990–91 period. Comparison of these with the analysis of the Southern System which would have some small excess of winter capacity shows that further exchange of something under 200 megawatts may be feasible in 1980, perhaps some 200 megawatts in 1985, and some 300 megawatts in 1990. On this basis, some 700 megawatts summer capacity might be available in 1990. These amounts in the earlier years are so small and the conditions for the later years so uncertain that little, if any, transmission for seasonal exchange purposes alone can be justified.

Transmission Patterns

Much of the existing transmission in Region III is at 115 kilovolts, with a substantial block of 161-kilovolt lines in TVA and nearby Southern System connections. Substantial amounts of 230-kilovolt transmission have been built in most sections except in TVA's 161-kilovolt and 500-kilovolt areas. There are two notable installations of 500-kilovolt transmission, one designed, among other things, to accomplish seasonal diversity exchange between TVA and the South Central Electric Companies. The other is the 500-kilovolt transmission system from Virginia Electric and Power Company's mine-mouth Mt. Storm Plant. Short sections of 500-kilovolt line are being built in North Georgia. In addition, Duke Power Company, Carolina Power & Light Company, Virginia Electric and Power Company, and TVA plan extensive 500-kilovolt overlays of their existing transmission systems.

Within Region III opportunities for mine-mouth steam-electric generating stations are limited. Mt. Storm and some areas in western Kentucky offer such opportunity. In contrast, coal mining in Alabama involves thin seams so that there may be only a moderate cost difference between locally mined coal and Kentucky coal shipped by unit train.

The capability of a single 230-kilovolt line is about 300 to 500 megawatts, depending on the length of line, type, size, and configuration of conductor. A typical 500-kilovolt line has a capacity of 1,500 to 2,000 megawatts, depending upon the same limiting factors. Therefore, the selection of transmission voltage will hinge largely on the size of generating units and plants. Because steam-plant sites are reasonably plentiful in certain areas of Region III, plants can be located relatively close to major load centers. This factor currently tends to favor 230-kilovolt transmission as being more economical than 500 kilovolts in those areas. In other areas, conditions are substantially different. Load and population density, higher fossil-fuel costs, and a relatively poorer inventory of steam-plant sites have indicated the development of large plants and large unit sizes. For the entire Region substantial amounts of 500-kilovolt transmission are forecast, amounting to 4,150 miles by 1980 and 9,019 miles by 1990. The maps, Figures 6, 7, and 8, show the general location of future high-voltage lines forecast for 1970, 1980, and 1990, respectively. The existence of transmission voltages higher than 500 kilovolts is recognized, and interest is maintained in current developments at 765 kilovolts. It is of historical significance and interest that the use of 500 kilovolts in this country had its beginning in this Region. Even with the present rate of load growth, one could expect that, because of the factors noted above, i.e., relatively intermediate distances between load and generation, the 500-kilovolt system is expected to suffice through the 1980's. The Region will continue to show interest

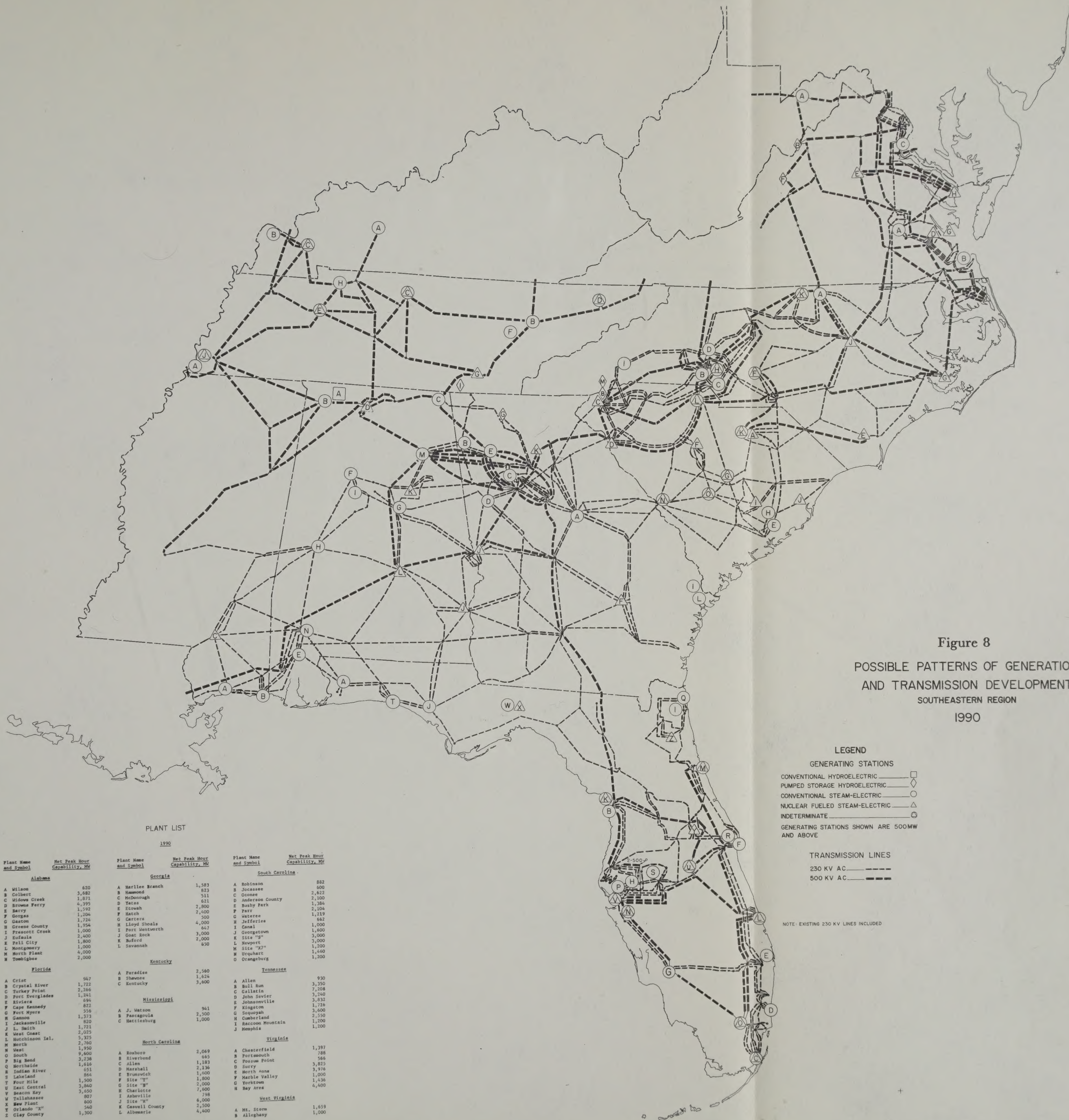

Figure 8

POSSIBLE PATTERNS OF GENERATION AND TRANSMISSION DEVELOPMENT

SOUTHEASTERN REGION

1990

LEGEND

GENERATING STATIONS

- CONVENTIONAL HYDROELECTRIC
- PUMPED STORAGE HYDROELECTRIC
- CONVENTIONAL STEAM-ELECTRIC
- NUCLEAR FUELED STEAM-ELECTRIC
- INDETERMINATE

GENERATING STATIONS SHOWN ARE 500MW AND ABOVE

TRANSMISSION LINES

- 230 KV AC
- 500 KV AC

NOTE: EXISTING 230 KV LINES INCLUDED

PLANT LIST

1990

Plant Name and Symbol	Net Peak Hour Capability, MW
Alabama	
A Wilson	620
B Colbert	3,682
C Widows Creek	1,871
D Browns Ferry	4,395
E Barry	1,592
F Gorgas	1,204
G Gaston	1,724
H Greene County	1,954
I Prescott Creek	1,000
J Eufaula	2,400
K Pell City	1,800
L Montgomery	1,000
M North Plant	4,000
N Tombigbee	2,000
Florida	
A Crist	947
B Crystal River	1,722
C Turkey Point	2,266
D Port Everglades	1,241
E Riviera	694
F Cape Kennedy	822
G Fort Myers	556
H Gannon	1,373
I Jacksonville	820
J L. Smith	1,721
K West Coast	2,025
L Hutchinson Isl.	5,325
M North	2,760
N West	1,950
O South	9,600
P Big Bend	3,238
Q Northside	1,616
R Indian River	651
S Lakeland	864
T Four Mile	1,500
U East Central	3,840
V Beacon Key	3,650
W Tallahassee	807
X New Plant	600
Y Orlando "X"	540
Z Clay County	1,300

Plant Name and Symbol	Net Peak Hour Capability, MW
Georgia	
A Harllee Branch	1,583
B Hammond	823
C McDonough	511
D Yates	621
E Etowah	2,800
F Hatch	2,400
G Carters	500
H Lloyd Shoals	4,000
I Port Wentworth	647
J Goat Rock	3,000
K Buford	2,000
L Savannah	650
Kentucky	
A Paradise	2,560
B Shawnee	1,624
C Kentucky	3,600
Mississippi	
A J. Watson	941
B Pascagoula	2,500
C Hattiesburg	1,000
North Carolina	
A Roxboro	2,069
B Riverbend	665
C Allen	1,183
D Marshall	2,136
E Brunswick	1,600
F Site "T"	1,800
G Site "B"	2,000
H Charlotte	7,600
I Asheville	798
J Site "R"	6,000
K Caswell County	2,500
L Albemarle	4,400

Plant Name and Symbol	Net Peak Hour Capability, MW
South Carolina	
A Robinson	882
B Jocassee	600
C Oconee	2,622
D Anderson County	2,100
E Bushy Park	1,384
F Parr	2,104
G Wateree	1,219
H Jefferies	662
I Canal	1,000
J Georgetown	1,600
K Site "S"	3,000
L Newport	3,000
M Site "X7"	1,200
N Urquhart	1,460
O Orangeburg	1,200
Tennessee	
A Allen	930
B Bull Run	3,350
C Gallatin	7,208
D John Sevier	3,240
E Johnsonville	3,832
F Kingston	1,726
G Sequoyah	3,600
H Cumberland	2,550
I Raccoon Mountain	1,200
J Memphis	1,200
Virginia	
A Chesterfield	1,397
B Portsmouth	788
C Possum Point	566
D Surry	3,825
E North Anna	3,976
F Marble Valley	1,000
G Yorktown	1,436
H Bay Area	4,400
West Virginia	
A Mt. Storm	1,659
B Allegheny	1,000

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and participation in the programs currently under way concerning the problems of EHV systems and hopefully looks forward to the selection of a level which will afford the greatest benefits when a voltage above 500 kilovolts becomes necessary. It is also recognized that the securing of transmission line rights-of-way is becoming more difficult and costly and that the maximum use of existing rights-of-way, in certain areas, accelerates the consideration of higher than normally used voltages. It is also the same factors of relative proximity of load to generation, together with the already high degree of coordination and resulting interchange that now exists, that preclude the serious consideration of d-c transmission at this time.

While 115- and 230-kilovolt underground transmission cables are in use in the area, some of the 115-kilovolt cables having been in use for over 20 years, additional increments are currently considered only in those congested or special areas where there is no other reasonable alternative. Where the conditions of extremely heavy load densities necessitate the establishment of load centers and high-rise building congestion precludes overhead construction, underground transmission cables are a required solution, but where the newer and artistically designed overhead facilities will blend into or harmonize with the environment, they are used. While this latter type of construction is more costly, the structures sometimes costing up to twice as much as the overhead construction used in open areas, it is still materially less expensive than underground construction. It has generally met with acceptance by the general public and the consequent savings to the utility of course represent a benefit to its customers.

Reliability

Generating Capacity

Rapid changes in the sizes of generating units and other system characteristics make it impracticable to assign a particular percentage for reserves, or to use any short-cut methods associated with the size of the largest unit or the several largest units. Instead, a probability basis tempered with judgment and experience may be appropriate. To the extent practicable, it should take into account the type and size of generating units, their expected forced outage rates, the daily peak loads of the system, and maintenance requirements scheduled so as to provide approximately equal risk or equal margin over a year. Reliability studies should take appropriate account of interconnections.

Reliability considerations are strongly influenced by the expected forced outage rates and also the maintenance requirements of generating units.

Recent studies indicate the desirability of factoring into reliability computations the probabilities that system loads, as influenced by abnormal temperatures, will exceed the median-weather predicted load by various amounts. Reasonable correlation of temperature and load is practicable, but predictions of temperatures for 4 to 6 years ahead (or even 1 year ahead) are futile. Therefore, the indicated course is a long-term study of weather deviations expressed on a probability basis to be factored into the over-all computations of reliability.

Transmission and Operation

Reliability from the transmission and operation view can be considered under two broad categories. The first deals with assurance of reliable service under moderate contingencies such as the loss of one or two generating units together with the most critical transmission line at the time of the system annual peak-hour load. Criteria of this type inherently provide for contingencies involving more elements at times other than system peak-hour load. It is feasible to treat this criterion on a probability basis. The other general basis involves the highly unusual multiple-failure contingency which, though rare, must be controlled to prevent cascading of the disturbance to areas which should remain unaffected.

Coordination of generation and transmission plans between neighboring utilities enhances reliability of each, provided each utility or group of utilities is itself planned to provide reliable service. Utilities and groups in the Southeast have had mutual emergency arrangements in effect for over two decades, and these have been highly effective in producing an excellent degree of reliability. These principles have been extended recently through reliability coordination agreements between neighboring groups. Such agreements are in effect between systems and groups within Region III, and between such groups and neighboring systems in Regions II and V. Negotiations are under way for similar arrangements between Region III entities and Region IV entities.

CHAPTER IV

STATEMENT OF COORDINATION

General

Coordination of operating procedures and planning for reliability of power supply are in effect between the various systems in the Southeast. This is being implemented by Reliability Coordination Agreements between neighboring systems and pools, as well as by joint study programs conducted by systems on a less formal basis. Discussions are now being held to put into effect other similar formal agreements.

In most cases, the work involved in coordination is carried out by committees or special working groups. These committees meet periodically for the purpose of discussing problems and implementing studies leading to increased reliability. These discussions and studies deal with matters such as generation and transmission planning, construction schedules, operation, maintenance schedules, spinning reserve requirements, and mutual assistance during emergencies.

Statements on coordination prepared by the various systems are listed below.

CARVA Pool

The CARVA Pool, comprised of Carolina Power & Light Company, Duke Power Company, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, was formed after several years' planning and negotiation directed toward increasing coordination over the wide geographical area served by the companies. The agreement, which went into full effect on May 1, 1967, was the culmination of efforts based on a mutual desire to attain maximum economy and bulk power supply reliability for the benefit of over 2.6 million customers in the States of North Carolina, South Carolina, Virginia, and a small part of West Virginia. Under the CARVA agreement, the companies are specifically committed to undertake joint planning and operation of transmission and generation. This now is being accomplished through various committees and special working groups on which each company has representation. Implementation of the agreement has permitted members to install larger size units with attendant economies in first cost and operation, and has resulted in the shared development of plans for an extensive EHV bulk power transmission system among the Pool companies. Some 450 miles of 500-kilovolt transmission will be in service by 1975, with a major portion completed by 1972.

Further, other such committees and special working groups plan and coordinate operational matters, generation schedules, construction and maintenance schedules, reserve requirements and power interchange.

The CARVA Pool companies, individually and collectively, continue to be active in working with area and regional groups interested in coordination of electric facilities for maximum reliability and economy of service to all customers in their service area.

In April 1967, the CARVA Pool members signed a reliability agreement with members of The Southern Company Power Pool intended to further augment reliability of each company's bulk power supply through coordination of the companies' planning for and operation of their generation and bulk power transmission facilities.

An inter-area reliability coordination agreement was executed between CARVA, East Central Area Reliability Coordination Committee, and Middle Atlantic Area Reliability Coordination Committee on November 15, 1968. A possible coordination agreement with TVA is also being studied.

Joint studies of bulk power transmission facilities are in progress between the CARVA companies and the American Electric Power System; CARVA and the Southern companies; and CARVA and the PJM interconnection.

All the CARVA companies have been part of the Interconnected Systems Group for many years.

Each individual member has interconnection

agreements with its neighbors which to a greater or lesser degree, involve purchase and sale of power, exchange of information, mutual assistance during emergencies, establishment of operating procedures and joint studies of plans for transmission affecting more than one company, all of which contribute to improved coordination. These interconnection agreements, for the most part, were in existence before formation of the CARVA Pool and before the inter-area agreements referred to above were concluded. They continue as effective complements to the more embracing inter-area agreements.

The CARVA Pool companies are represented on the National Electric Reliability Council.

The Florida Group

For purposes of this report, the five major utilities in Peninsular Florida, who coordinate their operations through informal committee action, are identified as the Florida Group; furthermore, for simplicity, this group is sometimes referred to as a "Pool" with the understanding the term is applied in the broadest sense, and does not connote a formal pool.

Peninsular Florida is served by five principal suppliers, Florida Power Corporation, Florida Power & Light Company, Tampa Electric Company, and the municipal systems of Jacksonville and Orlando. These suppliers, surrounded on three sides by water, subjected to hurricanes and the highest incidence of lightning in the nation, undertake to stand on their own feet and provide their own reserves. They are strongly interconnected and comprise what has come to be known as the Florida Group. In emergencies each supplier aids the Florida system in trouble to the maximum extent of its resources. Notwithstanding the fact that each Florida supplier operates his own system in the most economical manner consistent with its individual requirements and policies, there is a strong recognition of the need to coordinate operating matters.

An informal committee was established in January 1959 by the three investor-owned utilities listed above for considering and coordinating mutual problems relating to interconnected operation. The committee consisted of engineering and operating personnel, and informal meetings were held on a randomly scheduled basis. As the activities of the informal committee proved to be beneficial, representatives of the Jacksonville and Orlando municipal systems were asked to participate. They began participating several years ago, so that their operations would be better coordinated with those of the three investor-owned systems. The committee members have no authority to enter into contractual agreements, to commit their organization to construction of facilities, nor to establish practices which are not in accord with individual organization policy. The committee does serve as an excellent medium through which mutual operating problems are reviewed and resolved in such a manner that technical operations are very well coordinated. This committee, known as the Florida Operating Committee, now meets on a bi-monthly basis. In its meetings, it focuses attention on such matters as spinning reserve, underfrequency relay protection, relaying and adequate communications between dispatching centers. It also coordinates maintenance schedules and recommends and organizes long-range planning studies and stability examinations for use by the five individual utilities. There are no "pooling" contracts or commitments among these systems.

Spinning reserve is voluntarily shared and maintained to protect the instantaneous loss of the largest generating unit in service. The reserve is distributed to enough operating units with proper governor characteristics so that a frequency drop of less than five-tenths of a cycle will provide the full benefits of each member's share of assistance. The full share of each member's reserve must be available to all other members and not restricted by limitation of transformers, lines or other equipment. In abnormal situations where the spinning reserve of a member is either unavailable or only partially available, the member notifies the others so that their spinning reserves may be increased or reallocated as required. Every system disturbance is thoroughly analyzed by the operating committee to check the response of the generating units of each member in meeting the emergency. The amount of spinning reserve required is constantly under review.

To avoid an excessive number of generating units being out of service simultaneously for maintenance and to insure the maximum availability of installed reserves, the five individual systems coordinate their maintenance schedules through the Florida Operating Committee.

Load shedding has been used as an emergency procedure by members of the Florida Group since 1957. For some time two of the systems have had capability of shedding more than 1,000 megawatts of load by underfrequency relays, and since the five systems are strongly tied together, this protection

has been available to all five members as a second- or third-contingency back-up. Now, all members of the group have provided for such installations and a completely coordinated plan was fully implemented in late 1968. Each member has or will have a load shedding capability of at least 30 percent of its peak load, and each member's portion of load shedding will be available to other members during any emergency operation. Stability examinations are used to assist in determining the amounts and locations of load to be shed, and the frequencies for which the relays should be set.

Each of the five systems uses an on-line computer for dispatching, and the dispatching offices of the individual group members are new and modern. These offices are linked by excellent communication facilities consisting of microwave, leased circuits, teletype, and radio. They are also linked to the power plants and substations by excellent communication facilities. Information is exchanged constantly concerning loads, reserves, and unusual operating conditions. In time of emergencies, the dispatchers can communicate very quickly and take proper corrective steps on the basis of factual and up-to-the-minute information.

On December 1, 1967, Florida Power Corporation and the Southern System companies entered into a reliability coordination agreement for the purpose of augmenting coordination for reliability of bulk power supply. The agreement calls for the appointment of an Executive Committee which shall review principles and procedures on matters affecting bulk power supply, such as (1) coordination of generation and transmission planning, construction, operation, and protection; (2) coordination of interconnections for assistance in emergencies; (3) initiation of joint studies and investigations pertaining to emergency performance of bulk power supply facilities; (4) coordination of maintenance schedules of generating units and lines; (5) coordination of communication facilities; (6) coordination of load relief measures and restoration procedures; and (7) coordination of spinning reserve requirements.

Florida Power Corporation is represented on the National Electric Reliability Council.

Savannah Electric and Power Company

Savannah Electric and Power Company has an interchange contract with the Georgia Power Company and considers that the two companies are fully coordinated in the planning and operation of transmission systems and in generation requirements. Savannah has two 110-kilovolt transmission ties with Georgia Power. The primary purpose of these ties is for assistance of either company when the other company is in trouble. In fact, there is a provision in the interchange contract between Georgia and Savannah for establishing coordination for achieving maximum reliability in the operation of the two systems.

In order to assist both companies in planning future generation and transmission, joint network analyzer studies are made. These studies are the basis for determining the best operation for the two companies' systems and what additional transmission is required to best serve both companies.

The type of protection installed in existing ties was determined after joint conferences between the two companies. The type of relays and actual relay settings were determined by the relay sections of both companies working together. Savannah and Georgia consider that they have taken advantage of opportunities available for improving reliability and increasing efficiency which could not exist were they acting independently.

Through the foreging arrangements, Savannah is represented on the National Electric Reliability Council.

South Carolina Public Service Authority

The South Carolina Public Service Authority has an operating agreement with the South Carolina Electric & Gas Company and for many years has worked with its neighbors through interconnection agreements involving emergency support, economy power interchange, coordinated maintenance scheduling and direct sales and purchases. In addition, the Authority has a 1-year purchase power contract with South Carolina Electric and Gas Company for the year May 1, 1969, to April 30, 1970. The Authority's transmission system is connected with the CARVA Pool (through interchange points with the South Carolina Electric & Gas Company) at four locations, and future planning is expected to recognize additions of generation and transmission facilities in the area.

The Authority has been attempting to reach an agreement with the CARVA Pool whereby its customers may receive the full benefits of pooling opportunities such as installation of larger units with attendant economies, coordinated planning,

maintenance and operations, purchases and sales of power, and generally improving area reliability, and hopes in the future to complete an agreement satisfactory to all parties.

The Southern Company System

The Southern System covers approximately 122,000 square miles in the States of Alabama, Georgia, northwestern Florida, and southeastern Mississippi. The system is made up of six operating affiliates; namely, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Electric Generating Company (jointly owned by Alabama and Georgia), and Southern Services, Inc. (the engineering and operating service company for the Southern System).

There was some coordinated operation as early as 1921 between some of the operating companies and as early as 1925 among all four of the operating companies. The existing Pool contract has been in force since 1940 with revisions being made annually to reflect changing load and capability conditions.

Because of its early formation and common ownership, the Southern System has been able to evolve an integrated and fully coordinated generating and transmission system at all levels of operation. Full communication at all organizational levels ensures that planning and design take thorough and immediate advantage of operating experience, and this practice has led to the development of a generating and transmission system of very high reliability.

Separate reliability coordination agreements have been consummated with all neighboring systems, which are: CARVA (comprised of Carolina Power and Light Company, Duke Power Company, South Carolina Electric and Gas Company, and Virginia Electric and Power Company); Middle South System (comprised of Arkansas Power and Light Company, Louisiana Power and Light Company, Mississippi Power and Light Company, and New Orleans Public Services, Inc.); Florida Power Corporation; and Tennessee Valley Authority.

The work involved in these agreements is carried out by Executive Committees representing the participating systems. These committees are coordinating the two systems' generating and transmission planning, construction and operation, maintenance schedules, spinning reserve requirements, and other operating matters including the studies of methods of mutual assistance in emergencies.

Members of The Southern Company System are represented on the National Electric Reliability Council.

Tennessee Valley Authority

The Tennessee Valley Authority recently has signed Reliability Coordination Agreements with the Southern companies (consisting of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Services, Inc.) and the Middle South System (consisting of Arkansas Power and Light Company, Louisiana Power and Light Company, Mississippi Power and Light Company, and New Orleans Public Services, Inc.) and TVA is discussing similar agreements with other adjacent organizations. These agreements put on a more formal basis the cooperation, coordination, and exchange of information which has been taking place over the past years between TVA and its neighbors.

The South Central Electric companies and TVA have a program of making joint load flow studies annually, and joint transient stability studies when required.

Members of the planning organizations of TVA and American Electric Power Company meet periodically to discuss reliability and plan joint studies. These studies are carried out on a more or less continual basis and range from operating studies for the upcoming season to long-range planning studies.

The Tennessee Valley Authority also has made joint load flow studies with Union Electric Company and anticipates making additional studies as required.

These joint studies are made to determine interchange capability between systems under normal and emergency conditions, to determine the effect of new generation installations, to determine system flows following loss of generation, and to explore the feasibility of seasonal and emergency interchange.

The Tennessee Valley Authority is represented on the National Electric Reliability Council.

CHAPTER V

APPRAISAL OF UNDEVELOPED HYDROELECTRIC POTENTIAL IN THE SOUTHEAST

Scope

To the end that the updated National Power Survey will be comprehensive, this study of undeveloped hydroelectric potential in the Southeast (FPC Region III) has included review of 216 sites. Except for those developments already in service or under construction, this review embraced all undeveloped southeastern sites listed in the 1964 National Power Survey; in the FPC publication "Hydroelectric Power Resources of the United States, Developed and Undeveloped" dated January 1, 1964; in the U.S. Study Commission Report of the Southeast River Basins; and in the FPC staff testimony evaluating the 60 most promising southeastern sites as presented in the hearing leading to the licensing of Project No. 2503; in the FPC Planning Status Reports for each river basin; and 24 sites not mentioned in any of the above documents.

Of the 216 sites reviewed, 31 were studied in further detail, and only limited analyses were made of the remaining 185 sites for the following reasons:

Fifty sites are primarily pumped storage and are considered separately in a following section on pumped-storage potential.

Ninety-eight sites have less than 50 megawatts potential, were omitted from the 1964 National Power Survey, and are not of sufficient significance for inclusion in the updated survey.

Two sites are less feasible alternatives to nearby conflicting sites.

Thirty-five sites with a potential of 50 to 99 megawatts as listed in Appendix B were omitted from further analysis because:

1. Generally, these developments are too small to benefit from economies of scale, and therefore are unjustified when compared to more economical alternatives.
2. Fulfilling the forecast on page 127 of the 1964 National Power Survey, gas turbines have had widespread application in the Southeast. With a capacity cost of about $11 per kilowatt-year for the gas turbine, hydroelectric developments of less than 100 megawatts will rarely compete economically as a source of peaking capacity.
3. Since developments of 50 to 99 megawatts will be justified only very rarely, their omission from the updated power survey will not significantly understate the undeveloped hydro potential.
4. Developments in this size range are adequately documented in the Planning Status Report for each river basin, and it is unnecessary that they be included in the broader scope National Survey.

Economic studies to develop relative feasibility indices were made of the 31 sites which included the following categories:

Twenty-two sites having a potential of 100 megawatts or more of conventional hydroelectricity.

Four sites with previously estimated capacities ranging from 66 to 120 megawatts were treated as a single development of 186 megawatts which is the maximum combined potential that could be supported by stream flow and usable storage (Camp Creek, Rogues Ford, Sand Bottom, and War Woman).

Five sites of less than 100 megawatts were selected for further analysis because of special situations, such as likely additions to existing developments (Hartwell, Mitchell, and Saluda); benefits from reducing siltation of Charleston Harbor (St. Stephens); and prior authorization of site development by the Congress (Salem Church).

Feasibility Analysis Methods

To form a judgment as to which of the undeveloped potential would be built by 1980, by 1990, or not at all, an approximate index of feasibility for each development was calculated. For consistency, uniform economic criteria were applied to each development using analysis techniques similar in most respects to those in use by some Federal agencies. However, this does not infer committee agreement that the Federal economic criteria reflect full economic cost, neither does it suggest Federal development nor preclude development by others. For development by the investor-owned sector, higher fixed charge rates than used herein will tend to increase costs which may be offset by higher capacity and energy values with the result that relative feasibilities would be in the same range as shown.

The latest available investment cost estimate for each development was obtained from appropriate Federal agencies or utility companies as applicable. Each investment cost estimate was adjusted to January 1, 1968, price levels by use of the Handy-Whitman indices. Annual costs and values were then determined considering power and recreation only. Many of the developments would have other potential purposes such as flood control, water supply, pollution abatement, fish and wildlife values which would influence economic analysis on a government basis; or purposes such as cooling water and pumped-storage potential which would affect justification for investor-owned utilities. By limiting costs and values to power and recreation purposes, absolute values of justification could not be developed but only an index of feasibility. Thus the relative feasibility index reported herein for each project is analogous to the traditionally used benefit-cost ratio that would result from use of this chapter's costs and values for power and recreation, to the exclusion of other possible costs and benefits. Elements used in calculating the feasibility indices follow.

Annual Fixed Charges on Investment

Consistent with the policy set forth in Senate Document 97, as of June 30, 1967, Federal agencies were directed to use 3¼ percent interest rate in evaluating Federal water resource projects. This rate is to represent the average cost of all outstanding long-term borrowings of the government.

Although not consistent with investor-owned practices, a 100-year economic life was assumed for dams and reservoirs, and a 50-year economic life for specific power facilities. The resulting fixed charges as a percentage of investment are:

	Dam and reservoir (100-year life)	Specific power facilities (50-year life)
Interest	3.250	3.250
Amortization	.138	.823
Interim replacements	.050	.400
Insurance (in lieu of)	.002	.200
Total	3.440	4.673

Since the objective of these analyses was to determine only an index of feasibility and not its absolute value, and since detailed breakdowns of investment cost estimates were not available for each individual project, a composite fixed charge rate was uniformly applied to all projects. This composite rate was calculated on the assumption that the 100-year economic life would apply to 70 percent of the investment, and 30 percent had a 50-year life, thus giving a composite rate of $(0.70\times 3.440)+(0.30\times 4.673)=3.81$ percent. Neither the full cost of current money, to Federal or non-Federal entities, nor taxes, paid or foregone, are included in this fixed charge rate.

Annual Cost of Operation Maintenance

Figure 9 shows the variation in estimated operating and maintenance costs with the size of installations plus 35 percent for administrative and general expense.

Capacity Value

In the Southeast, the Commission staff in its financial feasibility analyses uses for capacity value the revenue obtained by the Federal marketing agency. This capacity value of $10.80 per kilowatt per year was assigned uniformly to all developments. This value is generally consistent with the fixed cost of about $11 per kilowatt per year incurred by investor-owned utilities in their recent gas turbine additions which are generally the most economic alternative sources of peaking power with which to compare proposed water power developments.

Energy Value

An incremental energy value of 2.65 mills per kilowatt-hour was assigned to the average annual energy expected from each development. This is, in general, the revenue obtained by the Federal marketing agency.

Recreation Costs and Values

Recreation costs usually include fixed charges on recreational facility investments as well as annual operation, maintenance, and replacement expenditures. Recreation values are generally a function of the size of reservoir, variations in the water surface elevations during the major recreational season, population density in the vicinity of the proposed development, presence of other nearby reservoirs, and quantity and quality of recreational facilities available. However, there is no uniform practice among the several agencies with respect to estimating recreation values. In making preliminary estimates, some techniques use only size of reservoir as the controlling factor. Accordingly, based on a study of sizes and recreational uses of Federally constructed reservoirs in the Southeast, a range of gross recreational values per acre and a range of costs per acre were obtained for various sizes of reservoirs. The results of that study were used to prepare the curves shown in Figure 10 which were used in making preliminary estimates of recreational costs and benefits for these analyses.

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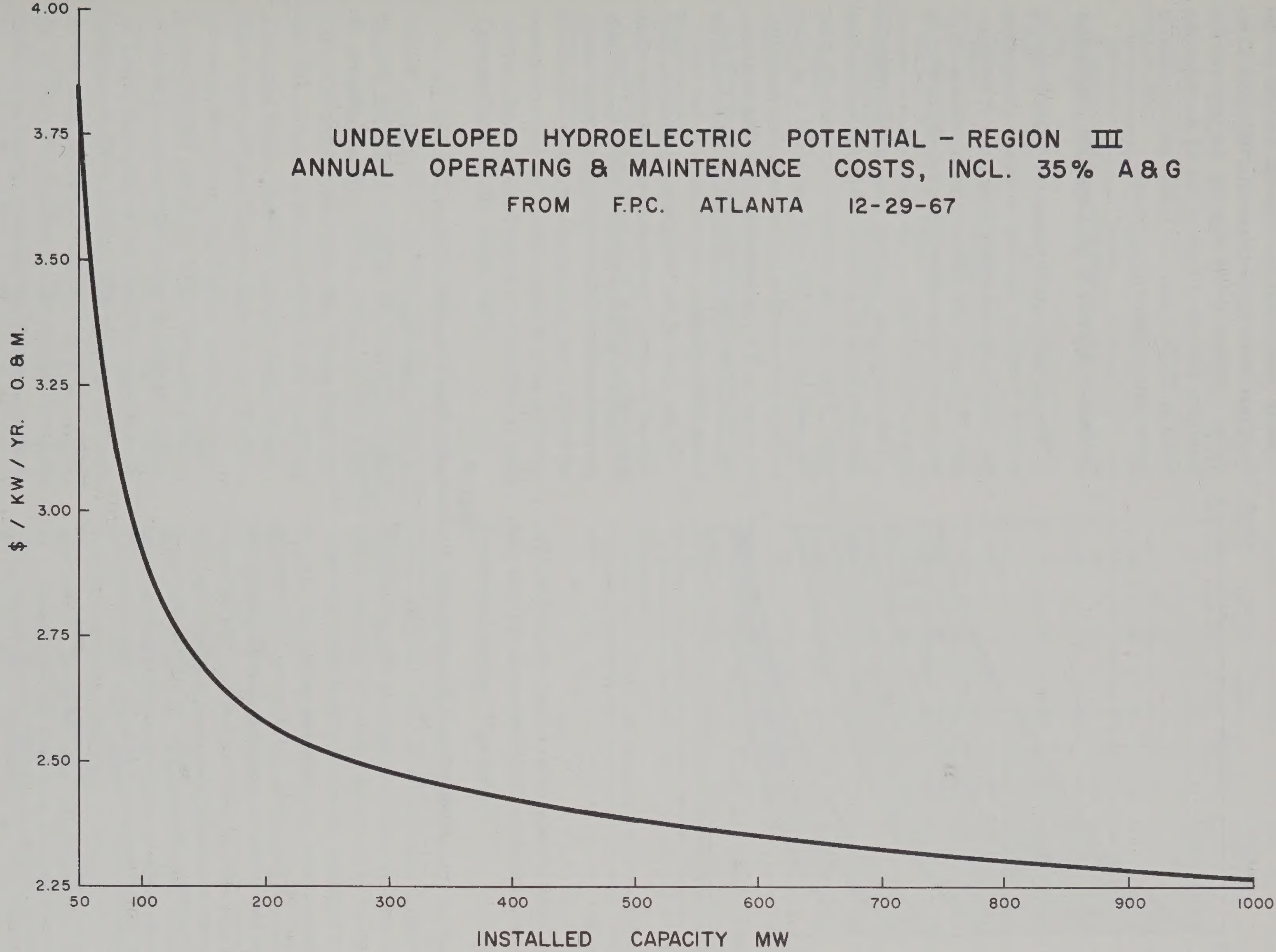

Figure 9

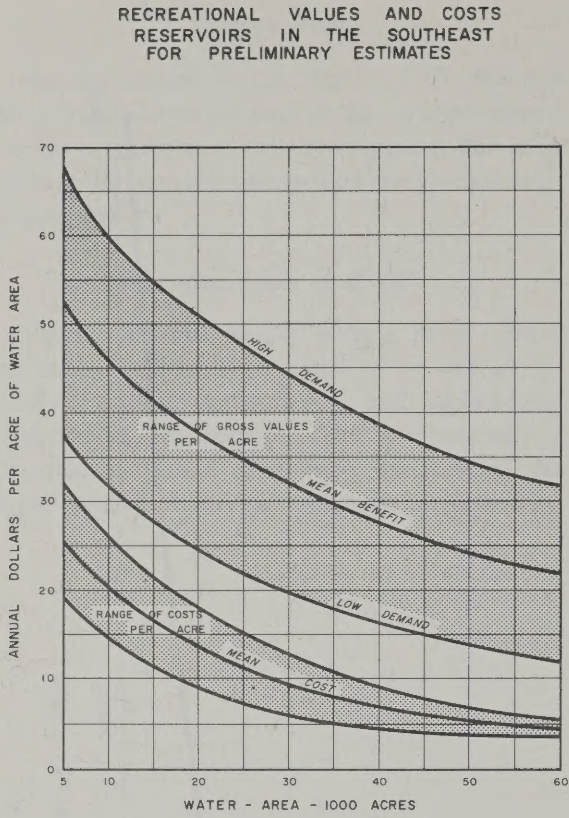

Figure 10

Results

Pertinent physical data and the relative feasibility index of each of the 28 developments (31 sites with four sites combined as a single development) are summarized in Table 9. The potential undeveloped capacity represented by these 28 projects in the Southeast totals 4,614 megawatts. Appendix C includes summary sheets showing the approximate feasibility analysis of each of the 28 developments listed in Table 9 and the Tellico project which is under construction without power.

Probable Schedule of Capacity Additions

Nine of the projects shown on Table 9 have a relative feasibility showing economic promise, as indicated by the index exceeding unity. It is reasonable to expect that these projects, totaling 1,378 megawatts of undeveloped potential, will be brought into service by 1980.

Five additional projects have an approximate feasibility index of about 0.8 or better but less than unity. These are less attractive economically than the previous nine, but with the addition of other multiple purposes that may enhance their feasibility, they may well be developed by 1990. The total conventional hydroelectric potential of these five projects is 785 megawatts.

In the case of the remaining 14 projects, their lack of economic justification suggests that their development with hydroelectric power as a primary purpose is unlikely. However, if special needs associated with other purposes of overriding importance accrue to some of these projects, hydroelectric power may be included as a somewhat incidental purpose.

TABLE 9
Undeveloped Conventional Hydroelectric Potential—FPC Region III

Drainage Basin—Site or project name	River	State	Potential capacity (mw)	Average annual generation (1,000 mwh)	Usable power storage (1,000 AF)	Gross static head (feet)	Relative feasibility index	Probable development mw by 1980	Probable development mw by 1990	Notes
Rappahannock Basin: Salem Church.	Rappahannock	Va	89	161	517	175	.79		89	
James Basin: Pemberton	James	Va	232	356	1,250	110	.68			
Roanoke Basin: Smith Mountain.	Roanoke	Va	150	131		195	1.65	150		1, 13
Santee Basin:										
St. Stephen	Santee	SC	84	(-110)		70	1.56	84		2
Frost Shoals	Broad	SC	183	232	35	68	.66			
Blairs	Broad	SC	180	222	160	80	.91		180	
Greater Lockhart	Broad	SC	284	319	850	174	.64			
Gr. Gaston Shoals	Broad	SC	105	129	60	'125	.71			
Saluda	Saluda	SC	78			188	1.79	78		3
Savannah Basin:										
Burtons Landing	Savannah	Ga&SC	100	273	90	48	.66			
Anthony Shoals	Broad	Ga	100	58	113	65	.83		100	
Tallow Hill	Broad	Ga	172	113	560	190	.71			
Trotters Shoals	Savannah	SC	310	471	57	152	1.17	310		4
Hartwell	Savannah	Ga	66			185	2.90	66		5
4 Chattooga	Chattooga	Ga&SC	186	246	93	749	.42			6

See footnotes at end of table.

TABLE 9—Continued
Undeveloped Conventional Hydroelectric Potential—FPC Region III—Continued

Drainage Basin—Site or project name	River	State	Potential capacity (mw)	Average annual generation (1,000 mwh)	Usable power storage (1,000 AF)	Gross static head (feet)	Relative feasibility index	Probable development mw by 1980	Probable development mw by 1990	Notes
Altamaha Basin:										
Ohoopee-Goose Cr	Altamaha	Ga	169	296	361	62	.56			
Laurens Shoals	Oconee	Ga	324	341		95	1.48	324		7
Coopers Ferry	Ocmulgee	Ga	120	189	420	78	.76			
Apalachicola Basin: Spewrell Bluff.	Flint	Ga	100	133	322	157	.62			
Tombigbee Basin: Smiths Ford.	Locus Folk	Ala	115	84	508	178	.72			8
Alabama Basin:										
Bridgeview	Tallapoosa	Ala	105	130	0	35	.61			
Martin	Tallapoosa	Ala	171	21	(−916)	146	1.65	171		9
Emuckfaw	Tallapoosa	Ala	181	196	284	121	1.08		181	10
Crooked Creek	Tallapoosa	Ala	135	149	161	130	1.04	135		11
Mitchell	Coosa	Ala	60	127	0	60	1.20	60		9
Tennessee Basin: Sugar Creek	Elk	Ala	100	140	325	85	.51			
Cumberland Basin:										
Devils Jumps	Big South Fork	Ky	480	475	1650	457	.77			13
Cumberland Falls-Jellico	Cumberland	Ky	235	355	392	346	.84		235	12, 13
Totals			4614	5237				1378	785	

NOTES:

1. Install 5th Unit in existing powerhouse.
2. Justification derives from special purpose to reduce silting in Charleston Harbor. Index=0.29 considering power only.
3. Install Unit 5 in existing powerhouse. S.C. Elec. & Gas has received license amendment.
4. Authorized by Congress in 1966.
5. Install Unit 5 in existing powerhouse.
6. Capacity limited to 186 mw by usable storage. Includes Camp Creek, Rogues Ford, Sand Bottom and War Woman developments.
7. Includes 216 mw reversible, license application by Georgia Power Company pending.
8. Licensed in 1950, construction abandoned, license offered for surrender.
9. Addition of new powerhouse to existing development of Alabama Power Company.
10. If military park cannot be inundated, feasibility index drops to 0.86.
11. Preliminary permit issued to Alabama Power Company.
12. Includes 90 mw reversible, formerly considered as two separate developments.
13. Output will be utilized in power supply areas outside the Southeast Region. Also included in East Central Regional Advisory Committee Report.

Comparison With 1964 NPS

In the 1964 National Power Survey, new hydroelectric projects and capacity additions projected to 1980 were listed on Table 37. This list included 62 projects located in the Southeast (FPC Region III). Of these, three have been completed and placed in service as additions to Cowans Ford, Lay Dam, and Walter Bouldin (formerly Jordan No. 2). Four more are now under construction: Keowee, Jocassee, West Point, and Tellico which is without power. Of the remaining 55, 27 sites are listed as 24 developments in Table 9 and 28 sites are omitted as having capacities of less than 100 megawatts. In addition, Table 9 includes four projects not listed in the 1964 National Power Survey. They are the St. Stephen development on the Santee River, the addition to Martin Dam and the Bridgeview development on the Tallapoosa and the Cumberland Falls-Jellico combination.

Pumped-Storage Potential

Particularly in the mountainous areas, the Southeast is endowed with an abundance of pumped-storage sites with an aggregate capacity many times that of the total potential capacity of all the undeveloped conventional hydroelectric resources in the Region. In some cases, pumped storage can be developed at conventional hydro sites to multiply the capacity of those installations without additional reservoir or dam costs. Generally, the high head sites are conducive to pure pumped-storage developments and will be the most economically attractive source of large blocks of future peaking capacity. Pumped storage is more related to topography than to river resources. The sites in the mountainous areas of the Southeast are literally too numerous for a meaningful tabular listing of sites.

Pumped-storage capacity in the Southeast is now in service at Smith Mountain and Hiawassee and under construction at Carters Dam and Jocassee. A

license application has been made for Laurens Shoals. Additional projects have been announced and are in the planning stages. Some high head pure pumped-storage developments have been estimated at current costs of about $100 per killowatt.

The 1964 National Power Survey cited several limitations of pumped-storage peaking power. These limitations included terrain restrictions, economic limits to transmission distances, competition from other types of peaking capacity, and availability of adequate supplies of low cost pumping energy. There has recently developed another potential limitation. During abnormally hot weather, the heavy air conditioning demand in the Southeast has caused sustained high-level peaks for 10 to 12 hours per day, five consecutive days per week. This pattern can recur for three to five consecutive weeks. Considering the amount of low-load-factor hydro capacity now existing that must remain in the top of the load curve, large blocks of new peaking capacity may have to deliver 40 to 60 kilowatt-hours each week per kilowatt of capacity. For pure pumped-storage installations where the water flow is about equal in the pumping and generating modes, this large peaking energy requirement will necessitate large storage reservoirs that cannot be replenished over night or even over some weekends. Alternatively, pumping capacity will have to exceed generating capacity if the reservoirs are to be replenished and have sufficient stored energy again available to meet sustained peak loads.

Statement of Separate Views

The task force report on the Appraisal of Undeveloped Hydroelectric Potential in the Southeast was accepted for inclusion in the Southeast Regional Advisory Committee report on Electric Power in the Southeast by majority vote at the Ninth Meeting of the Committee on December 4, 1968. Committee member, Charles W. Leavy, dissented contending that the report should consist only of an inventory of potential projects without any detailed economic evaluation; and that the analyses confuse economic analysis and financial analysis. Mr. Leavy's statement of separate views follows:

"The report on the 'Appraisal of Undeveloped Hydroelectric Potential in the Southeast' constitutes a summary of individual economic analyses of potential projects in the Southeast. Although the terminology is somewhat different from that of the usual economic analysis, the analyses are designed to determine economic feasibility and the so-called 'relative feasibility index' is stated to be 'analogous to the traditionally used benefit-cost ratio'. The propriety of such specific economic appraisals by the Regional Advisory Committee is questionable. However, more serious is the fact that, with respect to particular projects, the report is, at best misleading.

"While the report specifically states that benefits consider only power and recreation, the results are nevertheless misleading since other project purposes will, in many cases, contribute substantially to the benefits of a multi-purpose project.

"A more basic objection, however, to the specific analyses is that the analyses confuse economic analysis and financial analysis. An economic analysis which is made to determine a benefit-cost ratio is based upon power benefits, while a financial analysis is based upon potential power revenue. The report uses a supposed power revenue figure to determine benefits (or, as it terms them, 'values') to be used in an economic analysis. This results in a substantial understatement of capacity benefits (or 'values') with a resultant decrease in the benefit-cost ratio (or 'relative feasibility index'). The steps for determining the value of hydroelectric power for purposes of arriving at a benefit-cost ratio are set forth in some detail in Chapter II of the Federal Power Commission's March 1968 publication entitled 'Hydroelectric Power Evaluation'. This method has not been used in the report.

"In the case of Federal projects, the economic analysis which results in a benefit-cost ratio is normally made by the constructing agency, while the financial analysis determining the existence or not of financial feasibility for the inclusion of power in a project is made by the marketing agency. The latter analysis does not use benefits (or 'values'), but rather estimated potential power revenues. These may not necessarily be the prevailing Federal rates in the area since these rates are based not upon market value, but upon the costs of the particular projects to which they apply. This determination must also consider, if appropriate, the operation of a particular project integrated with the operation of other projects, as well as the financial consolidation of projects. It does not purport to result in any sort of a ratio or 'index' (since, under the law, this should approximate 1.0), but rather a determination of whether, under all the circum-

stances, costs properly allocable to power can be recovered during the repayment period.

"The 1964 National Power Survey, in Table 37, lists 62 projects in the Southeast area. The report eliminates nine projects on the basis, apparently, that a firm decision has been made either to develop or not to develop the projects. Twenty-eight projects are eliminated because they would have less than 100 megawatts of capacity. Fourteen projects, with 100 megawatts or more (the four Chattooga projects being considered as one project), have been eliminated on the basis of an unfavorable 'relative feasibility index'. Ten additional projects, having less than 100 megawatts, have been considered but not included on the basis of their size. Four additional projects, involving 100 megawatts or more, or special situations, have been identified but one (Bridgeview) has been eliminated on the basis of the 'relative feasibility index'. The net result of these changes is that the 1964 listing of 62 projects in the Southeast would be reduced to a listing of only 13 projects in the Southeast. Obviously, the 1964 report and the new report adopt vastly different criteria for the inclusion of projects.

"The 1964 listing is stated to be based upon an appraisal made by the Federal Power Commission staff. Revisions of the 1964 listing should also be based upon the same type of appraisal by the Federal Power Commission staff using the same criteria previously used or, if changes in criteria are made, the changes in criteria and their bases should be explained."

CHAPTER VI

FUELS

Introduction

The material in this Chapter is based on a report entitled, "Fuel Resources Requirements and Costs for Electric Generation in the Eastern United States," prepared by a special Fossil Fuel Resources Committee established to make a joint study for the Northeast, East Central, and Southeast Regional Advisory Committees. The Fuels Committee report has been published as a separate document, and it should be referred to for details not covered in this Chapter.

General Discussion

The Fuels Committee report brings up to date studies made for the 1964 National Power Survey (Survey 1964) of the Federal Power Commission, reflecting changes in technology, public policy, and energy trends since the original Survey, with particular reference to fuels used for electric generation. The period of analysis is extended by another 10 years, to 1990. Intervening developments that have significantly changed the fuel picture are identified and analyzed.

Two such developments with respect to fuels for electric generation that have assumed pre-eminence in the last few years are air pollution control and nuclear power. The nation's concern about the need for cleaner air is resulting in legislation at Federal, state, and local levels mandating, among other things, the use of fuels having a progressively decreasing sulfur content to minimize the emission of sulfur dioxide from electric power plants and industrial and residential heating installations, or the use of processes to reduce sulfurous emissions when fuels of higher sulfur content are used. Air pollution abatement will increase power generation costs which ultimately will be reflected in consumer rates, and will necessitate changes in historical fuel patterns as the demand for low-sulfur coal and oil tends to place undue strain on available short-term supplies.

For the longer term, 1971 and thereafter, the problems of air pollution may be reduced through the development of commercial fuel desulfurization techniques and the development of commercial stack emission control systems to supplement the limited supplies of naturally occuring low-sulfur fuels. Because natural gas is virtually sulfur-free, its use as boiler fuel is receiving increasing attention by industry and by the Federal Power Commission which must find the public interest in balancing the need for cleaner air against conservation of a depletable natural resource.

Nuclear power for electric generation has made and is continuing to make such impressive technological progress that the projections of nuclear's share of the fuel market in the 1964 Survey must be revised upward to a marked extent. The commercial development of fast breeder reactors will substantially alleviate the present factor of economically limited nuclear fuel reserves.

Other noteworthy developments include the rising trend in mine-mouth and midpoint electric plants with EHV transmission to distant load centers; the increasing acceptance of gas turbines and pumped storage for peaking power; "total energy" systems; and technologic progress in coal gasification.

The 1964 "National Power Survey" indicated that by 1980 nuclear capability would be supplying 10 percent of the Nation's kilowatt-hour generation.[1] Our current survey indicates that this 10 percent point will be reached in the Southeast Region in about 1972 and that nuclear power will account for 46 percent of the total generation by 1980, and 63 percent by 1990. This predicted growth is primarily the result of estimated reductions in the installed cost of large nuclear units from over $200 per kilowatt prior to 1964 to generally estimated figures of about $150 per kilowatt for plants to be completed in the 1967–1970 period. In the latter part of 1967 and early 1968, quoted prices for

[1] 1964 N.P.S. Vol. 2 Adv. Report No. 15, pg. 177.

nuclear steam supply systems increased substantially, and at a more rapid rate than for similar-sized fossil units. This component cost increase apparently has not yet been a deterrent to the competitive position of nuclear plants. For purposes of this report it has been assumed that nuclear plants will continue to be competitive, for units of 800 megawatts and up, although for comparable sizes and construction types, nuclear units will cost at least 20 percent more than coal-fired units.

Current concern about air pollution and the probability of air pollution control regulation in most of the metropolitan areas within the next few years introduces a large element of uncertainty into current fuel-use forecasts. However, it seems safe to predict an even higher percentage of nuclear generation, more interest in "mine-mouth" coal-fired plants remote for populated areas, more intensive development of low-sulphur fuel sources and emission control systems, and generally higher energy costs for all electric utilities. These higher costs eventually must be borne by the consuming public.

The Nation's known coal reserves are more than adequate to meet all the needs of the electric utilities, and all other users, through and well beyond 1990. Slightly over one-half of the Nation's total reserves of bituminous coal is within the three eastern regions covered by the Committee survey, and about one-third of this reserve is in the Appalachian area.

The long-term mine price of coal has trended downward until recently due to mechanization and improved productivity. (For the future, however, the results of this Committee's survey indicate increasing cost of coal at plants for electric generation.) This is particularly true for the Southeast, because of the long haul distances from mine to generating plant.

Most electric utility coal moves by rail, and here the development and use of "unit trains" has resulted in important cost savings. Further development of this concept into high speed "shuttle" trains may result in some transportation efficiencies, although rates for coal are increasing at the present time. The practicality of pipeline transportation of coal has been proven by a 108-mile line which operated successfully for several years. Further developments in pipeline transmission may well change the coal transportation picture considerably. Water shipments of coal have increased appreciably in recent years and are expected to continue as an important part of over-all coal transportation.

The delivered cost of natural gas to electric utilities has remained relatively stable since 1960. The Committee's survey indicates, however, that such cost is likely to increase. Gas is the easiest and least expensive of all fossil fuels to handle at electric generating stations, and the burning of gas minimizes air pollution problems. The role of natural gas in generating electricity in the Southeast is contingent on adequate supplies, and other factors, including regulatory policy with respect to optimum use of this depleting natural resource.

Fuel oil (residual) is of importance in power generation mainly in Florida. The future use of this fuel is contingent on Federal import policies and economic factors. Furthermore, domestic refineries now produce more profitable products from crude oil, resulting in less residual production. For these reasons it is expected that few new oil-burning utility generating units will be built.

Table 10 summarizes the anticipated use of major fuels for electric power generation in the Southeast during the 1970 to 1990 period.

Coal

As a result of increasing efficiencies in the production, distribution, and transportation of coal and in its utilization for power generation, coal accounted for approximately 65 percent of fuel consumed by electric utilities in the United States in 1966, on a total Btu basis.

Each year sees increasing quantities of coal used for the thermal generation of power, and it is generally accepted that, quantitatively, the trend will continue upward well beyond the period covered by this revision of the National Power Survey. The question is how it will relate, percentagewise, to other energy sources in response to changes which already are taking place in the energy mix, including the growth of nuclear power generation and growing pressures for the reduction of air pollution.

For the types of coal conventionally used for power generation, recoverable coal reserves are more than adequate to meet all foreseeable requirements far into the future. Reserves of low sulfur bituminous coals also are substantial. Because of higher mining costs and longer distances for transport, however, the costs of such coals will be higher and their availabilities will differ more or less directly in relation to the levels of sulfur content established in pollution abatement regulations. Fur-

thermore, the characteristics of low-sulfur coal are not always suitable for all types of furnaces.

Regional Distribution of Coal Reserves

Coal-bearing formations are widely distributed throughout the nation (Figure 11). On the basis of quantity, about 70 percent of the reserves are west of the Mississippi River. These deposits, however, are principally subbituminous coal and lignite, whereas the eastern coals are bituminous and anthracite. On the basis of calorific value, about 55 percent of the total reserve is east of the Mississippi River.

TABLE 10

Coal, Oil, and Gas Fuels for Electric Generation—Southeast Region (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970	
	Quantity	Equivalent tons	Quantity	Equivalent tons
Southeast:				
Coal (millions of tons)	63. 2	63. 2	84. 6	84. 6
Oil (millions of bbls.)	28. 0	7. 0	22. 6	5. 7
Gas (billions of cu. ft.)	140. 8	5. 8	218. 4	9. 0
Total		76. 0		99. 3
	1975		1980	
Southeast:				
Coal (millions of tons)	95. 4	95. 4	99. 6	99. 6
Oil (millions of bbls.)	19. 1	4. 8	18. 9	4. 7
Gas (billions of cu. ft.)	214. 8	8. 8	229. 3	9. 4
Total		109. 0		113. 7
	1985		1990	
Southeast:				
Coal (millions of tons)	108. 4	108. 4	121. 5	121. 5
Oil (millions of bbls.)	19. 8	5. 0	18. 7	4. 6
Gas (billions of cu. ft.)	340. 2	14. 0	422. 2	17. 4
Total		127. 4		143. 5

Note.—Fuel quantities are based on kilowatt-hour generation by fuels and weighted average heat rates, respectively, reported on the F.F.R.C. questionnaire, and were computed using the following conversion factors: 12,500 Btu per pound of coal; 150,000 Btu per gallon and 42 gallons per barrel of oil; 1,030 Btu per cubic foot of gas. The oil and gas equivalents per ton of coal are 4 barrels of oil and 24.3 MCF of gas, respectively.

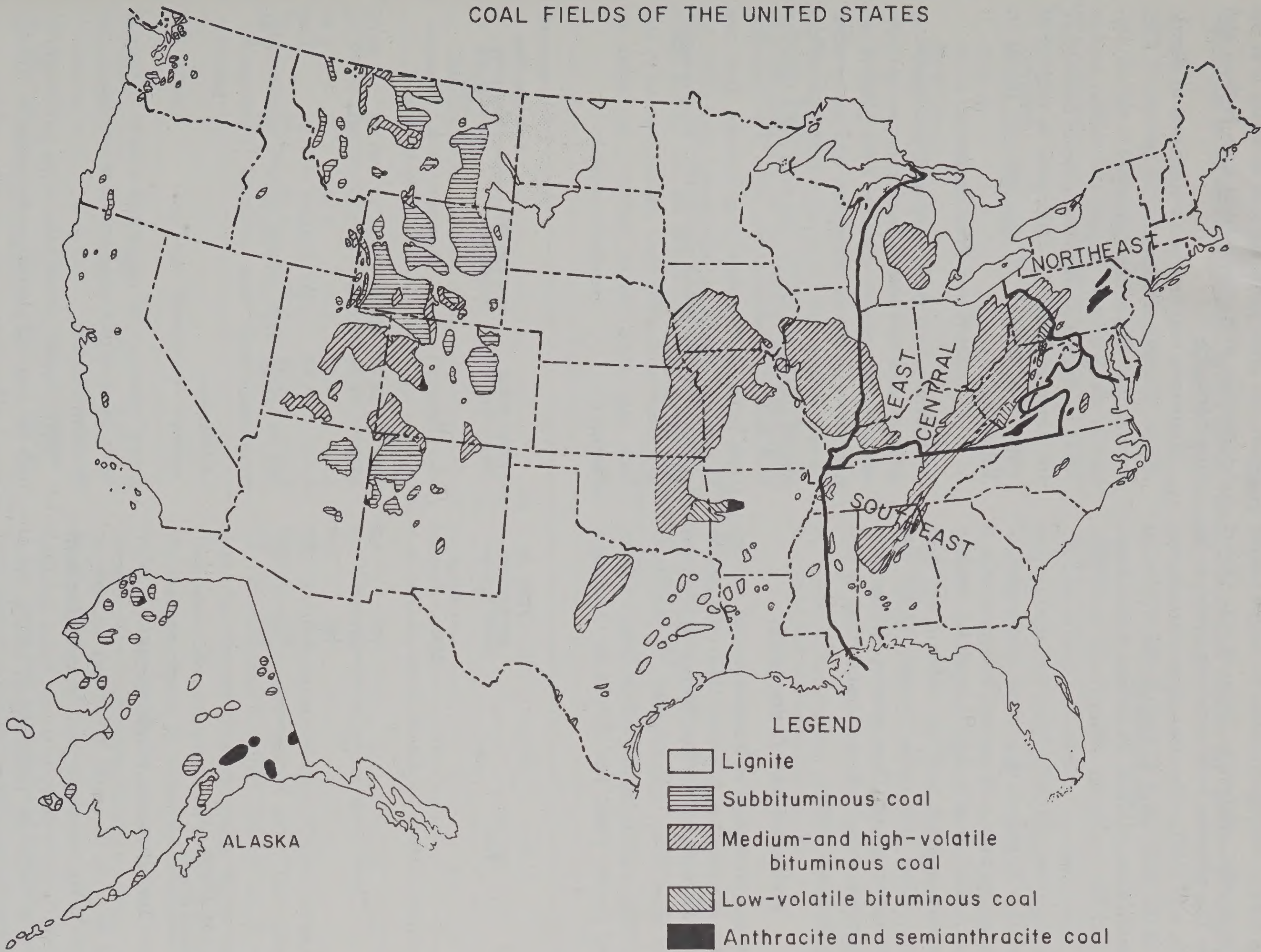
COAL FIELDS OF THE UNITED STATES
NORTHEAST
EAST
CENTRAL
SOUTHEAST
ALASKA
LEGEND
Lignite
Subbituminous coal
Medium-and high-volatile bituminous coal
Low-volatile bituminous coal
Anthracite and semianthracite coal

Figure 11

The coals of this region contain the largest reserve of high-quality, high-rank, coals in the United States. The estimated total remaining reserve in the Region is 271,000 million tons, approximately one-sixth of the total coal of all ranks in the country, on a tonnage basis, of which 95 percent is bituminous coal and the remainder Pennsylvania anthracite. The Appalachian bituminous coal reserve of 259,-000 million tons (129,500 million tons at 50 percent recovery) is 36 percent of total bituminous coal, of which approximately 84 percent is high-volatile, 9 percent medium-volatile, and 7 percent low-volatile. These coals generally have low moisture, and high calorific values that range between 12,500 and 14,500 Btu per pound. These reserves will also serve the members of the Northeast, East Central, as well as the Southeast Region.

Production and Consumption

National production of bituminous coal and lignite has increased steadily since 1961 (403 million tons) to an estimated 551 million tons in 1967, the highest since 1958. Approximately 83 percent of total output is produced in the three eastern regions covered by the Fossil Fuel Resources Committee report, the great preponderance of which is in the Appalachian area; the balance is in Indiana and West Kentucky.

Bituminous coal and lignite shipments to electric utilities currently account for 57 percent of U.S. consumption. Shipments from mines to electric utilities in the Southeast Region (67 million tons in 1967) by districts of origin and states of destination, are shown in Table 11. Shipments by districts of origin and methods of shipment are shown in Table 12.

Delivered Price Factors

Prices at which coal is and will be available in different areas vary with differences in mining methods and costs, quality, distances from point of extraction to points of utilization, and many other factors. Among the principal components of delivered coal prices are (1) the f.o.b. mine prices of coal and (2) transportation costs. The following table indicates the relationship between these two factors and trends for the period 1961–1966 for bituminous coal and lignite for the United States as a whole and in the three regions covered by the fuels task force report (referred to below as "Eastern"):

Year	Total production (million tons)		Average value f.o.b. mine		Average rail freight rate		Average mine value plus average rail rate	
	U.S.	Eastern	U.S.	Eastern [1]	U.S.	Eastern [2]	U.S.	Eastern
1961	403	336	$4. 58	$4. 64	$3. 40	$3. 45	$7. 98	$8. 09
1962	422	352	4. 48	4. 56	3. 32	3. 39	7. 80	7. 95
1963	459	383	4. 39	4. 46	3. 21	3. 28	7. 60	7. 74
1964	487	406	4. 45	4. 52	3. 11	3. 16	7. 56	7. 68
1965	512	426	4. 44	4. 54	3. 13	3. 17	7. 57	7. 71
1966	534	442	4. 54	4. 65	3. 01	[3] 3. 05	7. 55	7. 70

[1] Excludes Illinois.
[2] Includes Illinois.
[3] Preliminary.

Mine-Mouth Power Plants

The location of power generating facilities in coal-producing areas, at or near the mines, has been practiced for many years on a more or less localized basis. With important technological advancements in EHV transmission which permits the distribution of power over increasingly greater distances, and the further development of intertie, or grid systems, the potentials for increased growth of the mine-mouth concept have been broadened significantly. Table 13 shows "mine-mouth" plants with units of 500 megawatts or more that serve or will serve loads in the Southeast Region.

"Mine-mouth" plants have many advantages to both the coal and electric power industries. Among these are lessening of air pollution problems, particularly in those metropolitan areas in which generating facilities to meet increasing consumer demand would otherwise be located. They reduce the need for and the cost of transporting and handling

TABLE 11

Shipments of Bituminous Coal to Electric Utility Plants—Southeast Region (By Districts of Origin and States of Destination) Year 1967

[Thousand net tons]

States of destination	Districts of origin [1]					
	Total	7	8	9	10	13
Southeast:						
Tennessee	14, 777		7, 665	6, 375	46	691
Alabama and Mississippi	14, 550		108	6, 235	21	8, 186
Virginia	8, 896	811	8, 085			
North Carolina	14, 349	882	13, 467			
South Carolina	3, 877	19	3, 858			
Georgia and Florida	10, 519		5, 331	5, 059		129
Total Southeast	66, 968	1, 712	38, 514	17, 669	67	9, 006

[1] See Appendix D.

Source: Bureau of Mines, Department of the Interior. (Any differences between "shipments to" and "consumption at" electric utilities represent coal in transit, consumption from stocks, and other balancing factors.)

TABLE 12

Shipments of Bituminous Coal to Electric Utility Plants—Southeast Region (By Districts of Origin and Method of Shipment) Year 1967 [1]

[Thousand net tons]

Methods of shipment	Percent	Total	7	8	9	10	13
Southeast:							
All-rail	73	49, 227	1, 712	36, 945	7, 160		3, 410
River and ex-river	22	14, 649			10, 509	67	4, 073
Truck	3	1, 990		1, 569			421
Tramway, etc.[2]	2	1, 102					1, 102
Total Southeast	100	66, 968	1, 712	38, 514	17, 669	67	9, 006

[1] Source: Bureau of Mines, Department of the Interior.

[2] Tramway, conveyor, and private railroad.

TABLE 13

Mine-Mouth Electric Plants With Units of 500 Megawatts Capacity and Over—Southeast Region [1]

Plant	Megawatts	Operational	Operator
Paradise No. 1	700	1963	TVA
Paradise No. 2	700	1963	TVA
Paradise No. 3	1, 130	1969	TVA
Mt. Storm No. 1	570	1965	VEPCO
Mt. Storm No. 2	570	1966	VEPCO
Total	3, 670		

[1] There are several additional mine-mouth plants with units of less than 500 megawatts. Source: FPC "Steam-Electric Plant Construction Cost and Annual Production Expenses" various annual supplements.

coal in bulk form, as well as problems of storage and ash disposal in metropolitan areas. They give coal an increased and "captive" market which otherwise might be served by competing energy sources. They also make coal generated power available for the encouragement of economic enterprises over wider distances, from the local producing areas all along the line to distant consuming markets.

Natural Gas

The continued importance of natural gas to the fuel economy of the electric industry is unquestioned notwithstanding the phenomenal growth of nuclear power projected in the next two decades. The relatively pollution-free quality of natural gas has enhanced its value for producing electric energy, at least for the short term.

Natural gas requirements for all purposes in the United States during the next two decades are expected to increase at an average annual rate of approximately three percent, rising from 17.8 trillion cubic feet in 1966 to 36 trillion in 1990.[2] Gas as fuel for electric generation represented 14.6 percent of total U.S. natural gas requirements in 1966.

Reserves

Proven recoverable reserves of natural gas in the United States, exclusive of Alaska and Hawaii, approximated 286 trillion cubic feet as of December 31, 1966, according to estimates of the Committee on Natural Gas Reserves of the American Gas Association.[3] This is equivalent to about 12,000 million tons of high grade bituminous coal and is sufficient to last about 16 years based on 1966 net production of 17.5 trillion cubic feet.

The additional gas that ultimately may be discovered and produced—the potential gas supply—has been estimated as 690 trillion cubic feet as of the end of 1966. This estimate was made by the industry's Potential Gas Committee under the sponsorship of the Mineral Institute of the Colorado School of Mines, and represents gas supply not proved by drilling and therefore classified as "probable," "possible," or "speculative" depending upon geologic conditions and degree of exploration.[4] The Committee's estimate by supply areas and classifications is as follows (trillion standard cubic feet):

	East	Central	West	Total
Probable	55	220	25	300
Possible		170	40	210
Speculative	60	80	40	180
Total	115	470	105	690

The East supply area in the foregoing tabulation is approximately coterminous with the Northeast, East Central, and Southeast Regions of the National Power Survey study.

Gas for Electric Generation

Natural gas as fuel for electric generation in the United States during the five-year period from 1961 to 1966 increased from 1.8 to 2.6 trillion cubic feet,[5] an average annual growth rate of 7.4 percent for the period. The gas used for electric generation represented 14.6 percent of total natural gas requirements of 17.8 trillion cubic feet in 1966.

In the Southeast, it is estimated that gas for electric generation will increase from 141 billion cubic feet in 1966 to 422 billion in 1990.[6]

To the extent that natural gas for electric generation is off-peak or "valley" gas, it tends to promote pipeline economy by permitting a higher load factor operation than otherwise would be possible if pipeline loading were determined solely by gas consumers' daily and seasonal requirements. This results in lower rates for gas service to consumers.

The Federal Power Commission, which has jurisdiction over gas use through its regulation of interstate pipelines, has in special situations authorized some additional gas for use in electric generation. The Commision's policy in this respect is to determine the public interest in each individual case, balancing long-term conservation against short-term benefits of air pollution control and fuel economics.

The price of gas at the wellhead and to the consumer, including electric utilities, has remained relatively stable since 1960, as shown below.[7]

Average Wellhead and Consumer Price of Natural Gas

Year	Average wellhead (cents/MCF)	Consumer cost by class of service (cents/MCF)		
		Residential	Commercial	Industrial (including electric utilities)
1960	14.0	97	77	33
1961	15.1	100	78	34
1962	15.5	100	79	35
1963	15.8	100	79	35
1964	15.4	100	78	34
1965	15.6	100	78	35
1966	15.9	100	77	35

[2] Future Natural Gas Requirements of the U.S., Vol. No. 2, June 1967.

[3] Potential Supply of Natural Gas in the United States as of December 31, 1966, prepared by Potential Gas Committee.

[4] Ibid.

[5] Federal Power Commission: Electric Power Statistics.

[6] The increased usage of gas predicted by Southeastern Utilities in early 1968 when this report was prepared, has already been exceeded. Please see Addendum at the end of this chapter for current (June 1969) comments on gas and oil usage.

[7] American Gas Association, Gas Facts, 1966.

Coal Gasification

Technology for producing low-Btu synthetic gas from coal has long been available. The major emphasis in the development of coal gasification processes today is on the production of high-Btu gas with a minimum heating value of 950 Btu per cubic foot. A product of this quality could be blended with natural gas without seriously diminishing unit heating value, and could be transported economically through new or existing pipeline systems from points of manufacture to centers of consumption.

For different reasons, government, coal interests, and elements of the natural gas industry have joined to support research and development in coal gasification: government—to broaden the energy resource base; the coal interests—to develop new markets for coal; and the natural gas industry—to insure a long range supply of economical gaseous fuel. There has been a significant increase during the past five years in efforts directed toward coal gasification.

There are several reasons why coal is receiving favorable consideration:

1. Coal is an abundant indigenous resource.
2. Coal prices tend to remain relatively stable.
3. Coal is a relatively inexpensive feedstock for gasification processes. In most areas of the country coal or lignite is available at 10 to 20 cents per million Btu at the mine, whereas the price of the lowest grade petroleum product that might be used as feedstock for gasification is 40 to 50 cents per million Btu.

At present, the cost of manufacturing gas can only be estimated. With coal at 15 to 16 cents per million Btu the cost of producing gas by any one of the proposed gasification processes would be about 50 cents per million Btu. Depending on the size of the plant, the price of coal, credits for byproducts (sulfur), assumed rate of depreciation, and anticipated average return on equity capital, synthetic pipeline quality gas might be as low as 40 cents per million Btu. At present, the average price of natural gas available for resale near centers of consumption is 35 cents per million Btu.

Residual Oil

The outlook for residual oil for electric generation has been somewhat dimmed by two major developments since the National Power Survey was issued in 1964. First, the sudden emergence of environmental quality as a major public concern and the resulting emphasis on low-sulfur fuel. Second, the widespread acceptance of nuclear power with its economic incentive and its appeal as a pollutant-free source of energy, notwithstanding certain urban siting problems still to be resolved. The impacts of these and other developments are reviewed in this study.

Domestic residual fuel oil production dropped 21 percent between 1960 and 1966 despite increased refinery crude runs, as refineries converted their residuum to more economically attractive products. Asphalt production increased almost twice as fast as crude runs, while coke production grew almost three times as fast.

Electric utilities reporting to the Federal Power Commission increased their use of residual oil for electric generation from 86 to 141 million barrels between 1961 and 1966. The annual rate of increase was much greater in the later years but averaged 10 percent for the period.[8] Most residual oil is used in the coastal states where large tanker deliveries from Venezuela and, more recently, from Africa, minimize transportation cost.

Electric utilities in the Southeast included in the recent survey conducted for this report estimate that during the next two decades the amount of residual oil for electric generation will decrease both in absolute value—from 28 million barrels in 1966 to 19 million barrels in 1990—and percentagewise from 8 percent to 1 percent of total generation.[9]

Oil From Coal and Shale

Potential synthetic crude oils processed from reserves of coal, oil shale, and tar sands afford greater national security than the alternative of increasing reliance on oil imports. Industry sources estimate that 2.5 trillion barrels of synthetic oil could be recovered from United States coal reserves, plus 650 billion barrels from U.S. oil shale and 300 billion barrels from Canada's tar sand.[10] Synthetic crudes are not expected to be significant fuels for power generation in the Southeast before 1990.

[8] Federal Power Commission: Electric Power Statistics.

[9] The downward trend for oil predicted by Southeastern Utilities in early 1968, when this report was prepared, has not materialized. Please see addendum at the end of this chapter for current (June 1969) comments on gas and oil usage.

[10] National Coal Association: Coal News, March 1, 1968.

Nuclear Power

Introduction and Summary

Nuclear power technology progressed steadily from the days of the Shippingport, Dresden, Yankee, and Parr prototype generating stations of the late fifties and early sixties till about the end of 1965. At this point, a combination of competition in the budding nuclear industry, practicable light water reactor systems, and electrical system demands for large, economical units coincided. The result was an unparalleled surge in the industry to "go nuclear." During 1966, nearly one-half of the generation capability ordered was nuclear.[11] This phenomenal growth has been characterized by a broad and intensive industrial participation, with an awareness that the associated manufacturing and uranium industries must develop rapidly to meet the demand. Similarly, the need has become evident for fast breeder development to improve nuclear fuel resources utilization and to better utilize the expected plutonium production of the present generation of light water reactors. The relative availability and cost of fossil and nuclear fuels, improved capital investment aspects of larger nuclear systems, and the impact of air pollution on public opinion have been major considerations in fossil versus nuclear decisions. Indications are that nuclear power will assume an ever increasing role in power production, with a gradual transition to the economically advantageous fast breeder systems as that technology develops, predicted for the 1980's.

The great strides made in nuclear technology and the foresight of the Federal Government in encouraging private industry to put the nuclear industry on a free enterprise basis have gone far toward making nuclear power economically competitive. Fast-rising future energy requirements place even greater demands on development of nuclear power, and exploitation of all our fuel resources, and thus charges government and industry with having to meet these needs through the use of advanced concepts such as the fast breeder system, and more economical construction and operating techniques.

[11] "The State of the Nation's Power"—C. P. Avila, President EEI, speech to N.Y. Society Security Analysts January 17, 1968.

Operating Experience

Construction was started in April 1960 on a 17,000-kilowatt heavy water moderated and cooled pressure tube reactor project at Parr, South Carolina. The project was designed and built by Carolinas-Virginia Nuclear Power Associates (South Carolina Electric and Gas Company, Duke Power Company, Carolina Power and Light Company, and Virginia Electric and Power Company). The project began producing electricity in late 1963 as part of a 5-year operating research program. Saturated steam generated in the reactor was superheated by fossil fuel at the Parr steam-electric plant. Valuable experience was obtained from operation of the reactor. On December 31, 1967, the reactor was decommissioned.

As of January 1, 1968, there were 16 operable nuclear power stations in the United States totaling 2,810,000 kilowatts of capacity.[12] Units range in size from about 10,000 to 500,000 kilowatts of electrical generating capacity. The 462,000-kilowatt Connecticut Yankee Unit No. 1 (Haddam Neck, Connecticut) achieved criticality on July 24, 1967, and reached full power in January 1968. The 430,000-kilowatt San Onofre Plant of Southern California Edison and San Diego Gas and Electric went into regular commercial operation shortly after its dedication in January 1968. In 1967 the Peach Bottom (Phil. Elec. Co.) high temperature gas cooled reactor went into commercial operation, demonstrating the practicability of this concept. However, most of the reactor systems in operation are of the light water cooled and moderated variety. Experience from the pioneer 90,000-kilowatt Shippingport Plant (Duquesne Light Co.—1957), the 200,000-kilowatt Dresden Plant unit (Commonwealth Edison Co.—1959), and the 175,000-kilowatt Yankee Rowe Plant (Yankee Atomic Co.—1962) has shown over a period of years the practicality and dependability of light water reactor systems. Consolidated Edison's 265,000-kilowatt Indian Point Unit One (1962) is also building an impressive operating record. Operating, maintenance, and availability experience of these units has been such as to convince the electric utility industry that its new generating requirements can be met safely and reliably by nuclear power.

Twenty-three nuclear units are planned to go in service by 1975 in the Southeast.

[12] AEC Release January 11, 1968.

Nuclear Fuels

A milestone with significant beneficial effect on the electric power industry occurred with the passage of the Private Ownership of Special Nuclear Materials Act of 1964. This permits the orderly transfer from Government to private ownership of enriched uranium and plutonium produced by irradiation. The following table shows the timing of the related changes: [13]

TIME-TABLE

Private ownership permitted	August 26, 1964.
Toll enriching of privately owned uranium can begin.	January 1, 1969.
AEC prohibited from entering into new lease agreements for power reactor fuel.	January 1, 1971.
AEC guaranteed purchase price for plutonium will terminate.	December 31, 1970.
Private ownership of special nuclear material mandatory, all prior lease arrangements must terminate.	July 1, 1973.

This legislation already has generated, and will continue to generate, desirable competition in the nuclear fuel industry. The only component of the fuel cycle still in government hands is the enrichment process, and the Atomic Industrial Forum with the AEC has initiated a study of the feasibility and desirability of transferring to private industry one or more of the government's gaseous diffusion plants for fuel enrichment. The utilities are exhibiting an increased independence from reactor suppliers in making arrangements for reactor fuel loadings beyond those contracted for at the time of placing the nuclear steam supply system orders. The options available to utilities range from that of the reactor manufacturer's full fuel cycle service to that of the utility controlling many of the major steps in the fuel cycle. Recently, many of the companies involved in the nuclear fuel cycle industry announced plans for moves into, or expansions, to handle the new requirements. This, combined with the transition by the uranium supply industry from the guarantees of a government supported to a private market, is expected to have a long-range favorable effect on nuclear fuel economics.

[13] The Nuclear Industry—AEC, 1967.

Summary

Table 14 summarizes the anticipated energy source for electric power generation in Region III for the 1970 to 1990 period.

Addendum

Preparation of the Fuel Resources report began by the Fossil Fuel Resources Committee in June 1967 and drafting of the report was concluded in April 1968. The focal point of the report was a questionnaire on expected fuel requirements, which was designed by the Committee and mailed in the fall of 1967 to all electric utilities involved. The questionnaire and the data obtained from it are

TABLE 14

Electric Generation by Type of Fuel and Hydro Power—Southeast Region (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	161.1	73.6	218.1	74.7	245.8	57.0	259.4	41.8	282.3	32.9	316.4	26.9
Oil	18.0	8.2	14.7	5.0	12.4	2.9	12.4	2.0	13.0	1.5	12.3	1.0
Gas	14.8	6.8	23.2	7.9	22.8	5.3	24.6	4.0	36.5	4.3	45.3	3.9
Nuclear			7.2	2.5	114.5	26.6	286.7	46.3	487.2	56.8	761.3	64.7
Internal combustion			.3	.1	.1		.1		.3		.3	
Total	193.9	88.6	263.5	90.2	395.6	91.8	583.2	94.1	819.3	95.5	1135.6	96.5
Hydro generation:												
Conventional	25.0	11.4	28.7	9.8	31.8	7.4	31.8	5.1	29.7	3.5	27.5	2.3
Pumped storage					3.6	.8	4.8	.8	8.8	1.0	13.8	1.2
Total	25.0	11.4	28.7	9.8	35.4	8.2	36.6	5.9	38.5	4.5	41.3	3.5
Total generation	218.9	100.0	292.2	100.0	431.0	100.0	619.8	100.0	857.8	100.0	1176.9	100.0

described in greater detail in Part III of the Fuel Resources report. The survey was conducted independent of and prior to surveys conducted by the Task Force on Load Projection and the Task Forces on Patterns of Generation and Transmission.

The statistical tables presented in the report reflect future projections which are the sum total of the projections provided by the individual systems to the Committee in response to the questionnaire. This report, therefore, is essentially a reflection of the future fossil fuel supply and demand picture as seen by the utility users in the winter of 1967–68.

Since the report was completed, much has happened. Use of electric power increased more rapidly than expected. Nuclear power delays showed up. Air pollution control programs accelerated. Rail freight, and coal costs went up. Residual fuel oil prices went down markedly, and more low sulphur oil became available. As a result, electric utility fossil fuel consumption figures for 1967 and 1968, which have now become available, show that some of the fuel usage deviated significantly from those initially presented in the report.

The following tabulation is taken from Table 10, and covers the Southeast Region and is supplemented by actual figures on fuel consumption by those electric utilities for the years 1967 and 1968.

Consumption of Fuels—Southeast Region [1]

	Actual			Forecast				
	1966	1967 [2]	1968 [2]	1970	1975	1980	1985	1990
Coal	63.2	62.6	72.0	84.6	95.4	99.6	108.4	121.5
Oil	28.0	31.2	35.6	22.6	19.1	18.9	19.8	18.7
Gas	140.8	168.0	232.0	218.4	214.8	229.3	340.2	422.2

[1] Fuel quantities in millions of tons of coal, barrels of oil, and MCF of gas.

[2] Actual data published by FPC subsequent to completion of the report.

From the above figures it is evident that, at least for the short run, fuel oil consumption in the Southeast Region has taken a decided upward trend. Note also that natural gas consumption in the Southeast for 1968 has already exceeded the annual usage rates predicted for the period 1960 to 1980. Some of the reasons explaining these newly indicated trends have been noted above, and are discussed more fully in the Preface to the Fossil Fuel Resources Committee Report.

Because the initial figures included in this report present industry's own evaluation and expectations based on information available at the time, the Fossil Fuel Resources Committee felt that there was merit in publishing those figures without change, but including actual usages available to date for comparison.

APPENDIX A

Summary of Seasonal Capacity Exchange Potential—Megawatts

Year [1]	Carva	Florida	Southern	TVA	Total
1970					
Summer peak load less winter peak load	1, 181	750	1, 570	(2, 630)	
Capacity exchange potential [2]	[3] None	[3] None	310W	[6] 1, 800S	
Less existing or planned exchange			300W	[4] 1, 800S	
Net capacity for exchange	[3] None	[3] None	10W	None	10W
1975					
Summer peak load less winter peak load	2, 241	340	1, 980	(4, 200)	
Capacity exchange potential [2]	[3] None	[3] None	452W	[6] 1, 800S	
Less existing or planned exchange			300W	[4] 1, 800S	
Net capacity for exchange	[3] None	[3] None	152W	None	152W
1980					
Summer peak load less winter peak load	3, 796	375	2, 861	(5, 460)	
Capacity exchange potential [2]	[3] None	[3] None	491W	2, 243S	
Less existing or planned exchange			300W	[5] 2, 050S	
Net capacity for exchange	[3] None	[3] None	191W	193S	2S
1985					
Summer peak load less winter peak load	5, 942	470	4, 116	(6, 650)	
Capacity exchange potential [2]	[3] None	[3] None	536W	2, 630S	
Less existing or planned exchange			300W	[5] 2, 050S	
Net capacity for exchange	[3] None	[3] None	236W	580S	344S
1990					
Summer peak load less winter peak load	8, 678	710	5, 561	(7, 880)	
Capacity exchange potential [2]	[3] None	[3] None	607W	3, 068S	
Less existing or planned exchange			300W	[5] 2, 050S	
Net capacity for exchange	[3] None	[3] None	307W	1, 018S	711S

[1] Calendar year, except use greater of December, following January, or following February.

[2] After maintenance: S=Summer capacity; W=Winter capacity.

[3] Capacity required by reserve over peak is for maintenance.

[4] Including 1,500 MW outside Region III.

[5] Including 1,750 MW outside Region III.

[6] As estimated by TVA.

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Carva Pool Seasonal Exchange Potential [1]

	1970	1975	1980	1985	1990
1. Peak hour load (summer) MW	15, 140	22, 940	33, 532	48, 389	70, 241
2. Opposite peak (winter) MW	13, 959	20, 699	29, 736	42, 447	61, 563
3. Reserve—Percent of peak load	15. 0	15. 0	15. 0	15. 0	15. 0
4. Annual growth—Percent	8. 7	7. 9	7. 6	7. 7	7. 6
5. Capacity—June–December (7 months) percent	115. 0	115. 0	115. 0	115. 0	115. 0
6. Capacity—January–May (5 months) percent	105. 8	106. 6	106. 9	106. 8	106. 9
7. Base capacity (7 × (5) + 5 (6)) percent-months	1, 334. 0	1, 338. 0	1, 339. 5	1, 339. 0	1, 339. 5
8. Steam maintenance required	7. 74	8. 57	8. 90	9. 41	9. 71
9. Steam capacity—Percent of total	83. 2	87. 0	87. 0	87. 0	87. 0
10. Maintenance requirements—Percent of (7)	7. 23	7. 59	7. 87	8. 32	8. 58
11. Maintenance requirements—Percent-months	96. 4	101. 5	105. 4	111. 4	114. 9
12. Available for maintenance—Percent-months	120. 0	120. 0	120. 0	120. 0	120. 0
13. Less 5 months @ ((5) − (6)) percent-months	46. 0	42. 0	40. 5	41. 0	40. 5
14. Less maintenance requirements (11)	96. 4	101. 5	105. 4	111. 4	114. 9
15. Net for exchange—Percent-months	(22. 4)	(23. 5)	(25. 9)	(32. 4)	(35. 4)
16. Net for exchange ((15) ÷ 12) percent	0	0	0	0	0
17. Net for exchange ((16) × (1)) MW	0	0	0	0	0
18. Less 0.5 × (seasonal capacity difference)	0	0	0	0	0
19. Exchange potential—MW	0	0	0	0	0
20. Existing and planned exchange—MW	0	0	0	0	0
21. Net exchange potential—MW	0	0	0	0	0

[1] This analysis is a method of approximation to determine whether more specific studies are needed.

Peninsular Florida [1]

	1970	1975	1980	1985	1990
1. Peak hour load (summer) MW	8, 520	13, 340	20, 065	29, 255	41, 490
2. Opposite peak (winter) MW	8, 270	13, 000	19, 690	28, 785	40, 780
3. Reserve—Percent of peak load	28. 1	29. 1	25. 3	20. 2	19. 4
4. Annual growth—Percent	10. 0	9. 5	8. 5	7. 9	7. 2
5. Capacity—June–December (7 months) percent	128. 1	129. 1	125. 3	120. 2	119. 4
6. Capacity—January–May (5 months) percent	124. 0	124. 1	116. 5	116. 5	113. 8
7. Base capacity (7×(5)+5×(6)) percent-months	1, 517	1, 524	1, 460	1, 424	1, 405
8. Steam maintenance required—Percent	6. 0	6. 2	6. 8	7. 1	7. 4
9. Steam capacity—Percent of total	97. 3	98. 3	98. 8	98. 7	99. 1
10. Maintenance requirements—Percent of (7) [2]	5. 9	6. 1	6. 7	7. 0	7. 3
11. Maintenance requirements—Percent-months [3]	89. 5	93. 0	97. 8	99. 7	102. 6
12. Available for maintenance—Percent-months [4]	99	92	88	89	91
13. Less 5 months at ((5)−(6)) percent-months	20. 5	25. 0	44. 0	18. 5	28. 0
14. Less maintenance requirements (11)	89. 5	93. 0	97. 8	99. 7	102. 6
15. Net for exchange—Percent-months	(11. 0)	(26. 0)	(53. 8)	(29. 2)	(39. 6)
16. Net for exchange ((15)÷12) percent	(0. 9)	(2. 2)	(4. 5)	(2. 4)	(3. 3)
17. Net for exchange ((16)×(1)) MW	0	0	0	0	0
18. Less 0.5×(seasonal capacity difference)					
19. Exchange potential—MW	0	0	0	0	0
20. Existing and planned exchange—MW	0	0	0	0	0
21. Net exchange potential—MW	0	0	0	0	0

[1] This analysis is a method of approximation to determine whether more specific studies are needed.

[2] Steam maintenance times per unit steam plus other capacity in per unit times 1%.

[3] Base percent-months of capacity times weighted percent (line 10).

[4] From Chart of percent load each month—zero at peak month.

Southern System Seasonal Exchange Potential [1]

	1970	1975	1980	1985	1990
1. Peak hour load (summer) MW	11, 786	16, 616	24, 076	34, 616	47, 356
2. Opposite peak (Winter) MW	10, 216	14, 636	21, 215	30, 500	41, 795
3. Reserve—Percent of peak load	13. 5	14. 0	14. 5	15. 0	15. 5
4. Annual growth—Percent	8. 8	8. 5	8. 2	7. 9	7. 5
5. Capacity—June–December (7 months) percent	113. 5	114. 0	114. 5	115. 0	115. 5
6. Capacity—January–May (5 months) percent	104. 3	105. 1	105. 8	106. 6	107. 4
7. Base capacity (7× (5)+5 (6) percent-months	1, 316	1, 324	1, 330	1, 338	1, 346
8. Steam maintenance required—percent	7. 32	7. 78	8. 31	8. 65	8. 90
9. Steam capacity—Percent of total	76. 4	79. 2	82. 5	85. 1	85. 4
10. Maintenance requirements—Percent of (7) [2]	5. 83	6. 37	7. 03	7. 51	7. 75
11. Maintenance requirements—Percent-months [3]	76. 7	84. 3	93. 5	100. 5	104. 3
12. Available for maintenance—Percent-months [4]	166. 5	166. 5	165. 0	163. 5	162. 0
13. Less 5 months @ ((5)−(6)) percent-months	46. 0	44. 5	43. 5	42. 0	40. 5
14. Less maintenance requirements (11)	76. 7	84. 3	93. 5	100. 5	104. 3
15. Net for exchange—percent-months	43. 8	37. 7	28. 0	21. 0	17. 2
16. Net for exchange ((15)÷12) percent	3. 65	3. 14	2. 33	1. 75	1. 43
17. Net for exchange ((16)× (1)) MW	430	522	561	606	677
18. Less 0.5× (seasonal capacity difference)	120	70	70	70	70
19. Exchange potential—MW	310	452	491	536	607
20. Existing and planned exchange—MW	300	300	300	300	300
21. Net exchange potential—MW	10	152	191	236	307

[1] This analysis is a method of approximation to determine whether more specific studies are needed.

[2] Steam maintenance times per unit steam plus other capacity in per unit times 1%.

[3] Base percent-months of capacity times weighted percen (line 10).

[4] From chart of percent load each month—zero at peak month.

TVA System Seasonal Exchange Potential [1]

	FY 71 1970–71	FY 76 1975–76	FY 81 1980–81	FY 86 1985–86	FY 91 1990–91
1. Peak hour load (winter) MW	18, 050	26, 910	33, 410	39, 960	46, 560
2. Opposite peak (summer) MW	15, 420	22, 710	27, 950	33, 310	38, 680
3. Reserve—Percent of peak load	7. 2	7. 1	7. 8	8. 2	8. 3
4. Annual growth—Percent	6. 8	6. 8	4. 1	3. 4	2. 9
5. Capacity—October–June (9 months) percent	107. 2	107. 1	107. 8	108. 2	108. 3
6. Capacity—July–September (3 months) percent	100. 4	100. 3	103. 6	104. 6	105. 2
7. Base capacity (9 × (5) + 3 × (6)) percent-months	1, 266. 0	1, 264. 8	1, 281. 0	1, 287. 6	1, 290. 3
8. Steam maintenance required—percent	7. 97	8. 68	8. 99	9. 18	9. 31
9. Steam capacity—Percent of total	79. 1	81. 8	85. 5	87. 9	89. 6
10. Maintenance requirements—Percent of (7) [2]	6. 30	7. 10	7. 69	8. 07	8. 34
11. Maintenance requirements—Percent-months [3]	79. 8	89. 8	98. 5	103. 9	107. 6
12. Available for maintenance—Percent-months	186. 5	180. 4	187. 2	190. 0	192. 7
13. Less 3 months @ ((5) − (6)) percent-months	20. 4	20. 4	12. 6	10. 8	9. 3
14. Less maintenance requirements (11)	79. 8	89. 8	98. 5	103. 9	107. 6
15. Net for exchange—Percent-months	86. 3	70. 2	76. 1	75. 3	75. 8
16. Net for exchange ((15) ÷ (12)) percent	7. 19	5. 85	6. 34	6. 27	6. 32
17. Net for exchange ((16) × (1)) MW	1, 298	1, 574	2, 118	2, 505	2, 943
18. Less 0.5 × (seasonal capacity difference)	125	125	125	125	125
19. Exchange potential—MW	[4] 1, 423	[4] 1, 699	2, 243	2, 630	3, 068
20. Existing and planned exchange—MW	1, 800	1, 800	2, 050	2, 050	2, 050
21. Net exchange potential—MW	0	0	193	580	1, 018

[1] This analysis is a method of approximation to determine whether more specific studies are needed.

[2] Steam maintenance times per unit steam plus other capacity in per unit times 1%.

[3] Base percent-months of capacity times weighted percent (line 10).

[4] TVA's method of estimation indicates these figures to be in excess of 1,800.

APPENDIX B

Undeveloped Conventional Hydroelectric Potential in FPC Region III Having a Capacity of 50 to 99 mw and Not Included in Table 9

Drainage basin, site or project name	River	State	Potential capacity (mw)	Average annual generation (1,000 mwh)	Usable power storage (1,000 AF)	Gross static head (feet)	Remarks
James Basin Maury......	Maury.........	Va......	69	61	196	301	
Roanoke Basin:							
Schoolfield.........	Dan...........	Va......	76	93	145	86	
Randolph..........	Roanoke.......	Va......	50	73	135	66	
Melrose............	Roanoke.......	Va......	50	146	3	106	
Yadkin-Pee Dee Basin:							
Greater Blewett.....	Pee Dee........	NC......	82	367	179	80	
Crumps Ford.......	Rocky..........	NC......	79	90	220	135	
Junction...........	Yadkin.........	NC......	69	91	220	61	
Styers.............	Yadkin.........	NC......	54	76	185	65	
Upper Donnaha....	Yadkin.........	NC......	90	131	220	124	
Santee Basin:							
Buckingham Landing.	Santee.........	SC......	85	500	....	55	C of E study shows infeasible.
Clinchfield.........	Broad..........	NC......	59	69	390	140	C of E study shows power infeasible.
Courtney Island.....	Catawba.......	SC......	87	111	24	56	
Savannah Basin:							
Stokes Bluff........	Savannah.......	Ga......	60	225	100	35	
Horsepasture.......	Horsepasture....	NC......	58	93	12	1860	
Altamaha Basin:							
Murder Creek......	Murder Creek...	Ga......	60	126	205	128	River diversion infeasible.
Abbeville..........	Ocmulgee......	Ga......	79	149	699	63	
Apalachicola Basin:							
New Riverview.....	Chattahoochee..	Ga.......	65	115	....	39	
Franklin...........	Chattahoochee..	Ga.......	50	108	20	50	
Cedar Creek........	Chattahoochee..	Ga.......	50	101	134	60	
Morgan Falls.......	Chattahoochee..	Ga.......	58	157	94	117	Partially done. Further development infeasible.
New Bridge.........	Chestatee.......	Ga.......	50	34	250	156	
Lower Auchumpkee.	Flint...........	Ga.......	81	123	135	86	
Lazer Creek........	Flint...........	Ga.......	87	122	88	126	
Tombigbee Basin:							
Dorsey Creek.........	Mulberry Fork..	Ala......	63	61	420	135	

Undeveloped Conventional Hydroelectric Potential in FPC Region III Having a Capacity of 50 to 99 mw and Not Included in Table 9—Continued

Drainage basin, site or project name	River	State	Potential capacity (mw)	Average annual generation (1,000 mwh)	Usable power storage (1,000 AF)	Gross static head (feet)	Remarks
Alabama Basin:							
Wallahatchee	Tallapoosa	Ala	89	97	0	37	
Thurlow	Tallapoosa	Ala	50	0	....	96	Addition to existing plant.
Oakfuskee	Tallapoosa	Ala	52	46	600	107	
Kingston	Etowah	Ga	69	74	83	70	
Gilmer	Etowah	Ga	69	60	370	160	
Tennessee Basin:							
Austral	Hiwassee	Tenn	70	170	87	121	
Fines Cr	Pigeon	NC	60	115	335	302	
Erwin	Nolichucky	Tenn	65	160	497	268	
Surgoinsville	Holston	Tenn	72	172	35	75	
Nemo	Tenn	Tenn	80	190	170	366	
Cumberland Basin:							
Celina	Cumberland	Ky	69	227	10	50	

APPENDIX C

UNDEVELOPED CONVENTIONAL HYDROELECTRIC POTENTIAL

APPROXIMATE FEASIBILITY ANALYSIS

1 Development: Salem Church
River Basin: Rappahannock
River: Rappahannock
Capacity: 89,000 kw
Average annual energy: 161×10^6 kwh
Reservoir surface area: 47,450 acres
Estimated investment cost: $72,339,000
Source of estimate: C of E Review Report 5/2/66
Date of estimate: Mid-1965, HW index then 887
Ratio HW indexes: 1.09 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $78,800,000

Annual Costs:

Fixed charges on $78,800,000@ 3.81%	$3, 000, 000
Annual O&M @ $3.00/kw/yr	267, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	----------
Total annual costs	3, 267, 000

Annual Values:
Power:

Capacity of 89,000 kw @ $10.80/kw/yr	961, 000
Energy of 161×10^6 kwh @ 2.65 mills	427, 000
Recreation 47,450 acres @ $25/acre/year	1, 186, 000
Total annual values	2, 574, 000

Relative feasibility index=0.79 considering power and recreation only.

References:
C of E Review Report 5–2–66
FPC Form 557 revised 1–2–68

Remarks
Other annual benefits estimated by C of E include:

Flood control	$157, 000
Water supply	340, 000
Water quality control	607, 000
Salinity control	1, 490, 000

A smaller development was authorized by the Congress

2 Development: Pemberton
River Basin: James
River: James
Capacity: 232,000 kw
Average annual energy: 356×10^6 kwh
Reservoir surface area: 62,000 acres
Estimated investment cost: $135,800,000
Source of estimate: FPC Form 557
Date of estimate: Mid-1960; HW index then 811
Ratio HW indexes: 1.190 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $161,500,000

Annual Costs:

Fixed charges on $161,500,000 @ 3.81%	$6, 150, 000
Annual O&M @ $2.53/kw/yr	587, 000
Recreation fixed charges and O&M @ $4.60/acre/yr	285, 000
Total annual costs	7, 022, 000

Annual Values:
Power:

Capacity of 232,000 kw @ $10.80/kw/yr	$2, 506, 000
Energy of 356×10^6 kwh @ 2.65 mills	943, 000
Recreation: 62,000 acres @ $21.70/acre/year	1, 345, 000
Total annual values	4, 794, 000

Relative feasibility index=0.68 considering power and recreation only

References:

- C of E Report 9–1–45
- FPC Form 557, 11–65
- FPC Staff testimony on Project No. 2503
- FPC Planning Status Report, James River Basin, 1964

Remarks: Other potential purposes: Flood control, navigation, water quality control

3 Development: Smith Mountain
River Basin: Roanoke
River: Roanoke
Capacity: 150,000 kw
Average annual energy: 131×10^6kwh (191×10^6 kwh input pumping energy)
Reservoir surface area: None
Estimated investment cost: $5,400,000

- Source of estimate: $36/kw for machinery
- Date of estimate: 1967; HW index then 946
- Ratio HW indexes: 1.021 (1–1–68 index=966, Table 6, Line 15)
- Trended investment cost: $5,510,000

Annual Costs:

Fixed charges on $5,510,000 @ 4.67%	$258, 000
Annual O&M @ $1.50/kw/yr plus $707,000 pumping energy	932, 000
Recreation fixed charges and O&M @ $0/acre/yr	0
Total annual costs	1, 190, 000

Annual Values:

Power:

Capacity of 150,000 kw @ $10.80/kw/yr	$1, 620, 000
Energy of 131×10^6 kwh @ 2.65 mills	347, 000
Recreation 0 acres @ $0/acre/year	0
Total annual values	1, 967,000

Relative feasibility index=1.65 considering power and recreation only

References:

- FPC Form 557 of 10–26–66
- License for Project No. 2210

Remarks:

Add conventional unit to existing powerhouse (4 units existing, 2 conventional and 2 reversible)

Fixed charge rate of 4.67% used for specific power facilities as shown on page 5-3 of report

4 Development: St. Stephen
River Basin: Santee
River: Santee
Capacity: 84,000 kw
Average annual energy: (-100×10^6) kwh
Reservoir surface area: None
Estimated investment cost: $37,592,000

- Source of estimate: C of E Report 7–1–66
- Date of estimate: Mid-1966; HW index then 924
- Ratio HW indexes: 1.046 (1–1–68 index=966, Table 6, Line 15)
- Trended investment cost: $39,321,000

Annual Costs:

Fixed charges on $39,321,000 @ 4.673%	$1, 837, 000
Annual O&M @ $ special/kw/yr	191, 000
Recreation fixed charges and O&M @ $0/acre/yr	0
Total annual costs	2, 028, 000

Annual Values:

Net power benefits (1)	$417, 000
Other benefits, particularly navigation (1)	2, 750, 000
Total annual values	3, 167, 000

Relative feasibility index=1.56 considering power and recreation only

References: "Survey Report on Cooper River, S.C. (Shoaling in Charleston Harbor)", Charleston District Engineer, C of E, July 1966

Remarks:

Special purpose: to reduce silting in Charleston Harbor (1) Values relate to Santee-Cooper's costs, see C of E report

Omitting navigation benefits, relative feasibility index for power only on basis consistent with other developments evaluated would be:

Fixed charges	$1, 837, 000
Annual O & M (3.05)	256, 000
Total	2, 093, 000
Capacity benefits @ 10.80	908, 000
Energy loss @ 2.6 mills	260, 000
Total	648, 000

Index=0.31

5 Development: Frost Shoals
River Basin: Santee
River: Broad (S.C.)
Capacity: 183,000 kw
Average annual energy: 232×10^6 kwh
Reservoir surface area: 8,900 acres
Estimated investment cost: $102,745,000
Source of estimate: Draft-Santee Appraisal Report
Date of estimate: Mid-1966; HW index then 924
Ratio HW indexes: 1.046 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $107,200,000

Annual Costs:

Fixed charges on $107,200,000 @ 3.81%	$4, 095, 000
Annual O&M @ $2.60/kw/yr	476, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	4, 571, 000

Annual Values:

Power:

Capacity of 183,000 kw @ $10.80/kw/yr	$1, 978, 000
Energy of 232×10^6 kwh @ 2.65 mills	615, 000
Recreation 8,900 acres @ $47.00/acre/year	418, 000
Total annual values	3, 011, 000

Relative feasibility index=0.66 considering power and recreation only
References:
Preliminary Draft, FPC's Santee Basin Appraisal Report
HD 96, 73rd Congress, 1st Session ("308 Report")
FPC Staff testimony on Project No. 2503
FPC Planning Status Report, Santee River Basin, 1964
Remarks: None

6 Development: Blairs
River Basin: Santee
River: Broad (SC)
Capacity: 180,000 kw
Average annual energy: 222×10^6 kwh
Reservoir surface area: 37,900 acres
Estimated investment cost: $87,484,000
Source of estimate: Draft-Santee Appraisal Report
Date of estimate: Mid-1966; HW index then 924
Ratio HW indexes: 1.046 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $91,400,000

Annual Costs:

Fixed charges on $91,400,000 @ 3.81%	$3, 480, 000
Annual O&M @ $2.61/kw/yr	470, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	3, 950, 000

Annual Values:

Power:

Capacity of 180,000 kw @ $10.80/kw/yr	$1, 944, 000
Energy of 222×10^6 kwh @ 2.65 mills	588, 000
Recreation 37,900 acres @ $28.60/acre/year	1, 082, 000
Total annual values	3, 614, 000

Relative feasibility index=0.91 considering power and recreation only
References:
Preliminary Draft, FPC's Santee Basin Appraisal Report
HD 96, 73rd Congress, 1st Session ("308 Report")
FPC Staff testimony on Project No. 2503
FPC Planning Status Report, Santee River Basin, 1964
Remarks: None

7 Development: Greater Lockhart
River Basin: Santee
River: Broad (S.C.)
Capacity: 284,000 kw
Average annual energy: 319×10^6 kwh
Reservoir surface area: 58,600 acres
Estimated investment cost: $146,869,000
Source of estimate: Draft-Santee Appraisal Report
Date of estimate: Mid-1966; HW index then 924
Ratio HW indexes: 1.046 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $153,400,000

Annual Costs:

Fixed charges on $153,400,000 @ 3.81% ---------- $5,845,000

Annual O&M @ $2.50/kw/yr--- 710,000

Recreation fixed charges and O&M @ $ incl/acre/yr------ ---------

Total annual costs--------- 6,555,000

Annual Values:

Power:

Capacity of 284,000 kw @ $10.80/kw/yr ---------- $3,067,000

Energy of 319×10⁶ kwh @ 2.65 mills-------------- 845,000

Recreation 58,600 acres @ $22.30/acre/year ------- 1,307,000

Total annual values--- 4,219,000

Relative feasibility index=0.64 considering power and recreation only

References:

Preliminary Draft, FPC's Santee Basin Appraisal Report

HD 96, 73rd Congress, 1st Session ("308 Report")

FPC Staff testimony on Project No. 2503

FPC Planning Status Report, Santee River Basin, 1964

Remarks: Would inundate existing Lockhart Power Company 12,300 kw plant

8 Development: Greater Gaston Shoals

River Basin: Santee

River: Broad (S.C.)

Capacity: 105,000 kw

Average annual energy: 129×10⁶ kwh

Reservoir surface area: 5,530 acres

Estimated investment cost: $54,026,000

Source of estimate: Draft-Santee Appraisal Report

Date of estimate: Mid-1966; HW index then 924

Ratio HW indexes: 1.046 (1–1–68 index =966, Table 6, Line 15)

Trended investment cost: $56,500,000

Annual Costs:

Fixed charges on $56,500,000 @ 3.81% ------------------- $2,153,000

Annual O&M @ $2.88/kw/yr--- 302,000

Recreation fixed charges and O&M @ $ incl/acre/yr------ ---------

Total annual costs--------- 2,465,000

Annual Values:

Power:

Capacity of 105,000 kw @ $10.80/kw/yr ---------- $1,134,000

Energy of 129×10⁶ kwh @ 2.65 mills-------------- 342,000

Recreation 5,530 acres @ $51.20/acre/yr --------- 283,000

Total annual values--- 1,759,000

Relative feasibility index=0.71 considering power and recreation only

References:

Preliminary Draft, FPC's Santee Basin Appraisal Report

HD 96, 73rd Congress, 1st Session ("308 Report")

FPC Staff testimony on Project No. 2503

FPC Planning Status Report, Santee River Basin, 1964

Remarks: Would inundate existing 9,140 kw Gaston Shoals plant

9 Development: Saluda

River Basin: Santee

River: Saluda

Capacity: 78,000 kw

Average annual energy: Negligible additional kwh

Reservoir surface area: Existing acres

Estimated investment cost: $6,700,000

Source of estimate: S.C. Electric & Gas Co.

Date of estimate: 1968; HW index then 0

Ratio HW indexes: 1.0 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $6,700,000

Annual Costs:

Fixed charges on $6,700,000 @ 4.67% ---------------------- $313,000

Annual O&M @ $2.00/kw/yr----- 156,000

Recreation fixed charges and O&M @ $0/acre/yr--------------- 0

Total annual costs----------- 469,000

Annual Values:

Power:

Capacity of 78,000 kw @ $10.80/kw/yr ----------- $841,000

Energy of negligible kwh @ 0 mills------------------ 0

Recreation 0 acres @ $0/acre/year --------------- 0

Total annual values----- 841,000

Relative feasibility index=1.79 considering power and recreation only.

References: S. C. Electric & Gas application for amendment to license

Remarks:

Addition of Unit 5 to vacant bay in existing powerhouse

Existing four units have a nameplate capacity of 130,000 kw total

16 Development: Burtons Landing

River Basin: Savannah

River: Savannah

Capacity: 100,000 kw

Average annual energy: 273×10^6 kwh

Reservoir surface area: 59,000 acres

Estimated investment cost: $101,328,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1963; HW index then 853

Ratio HW indexes: 1.133 (1–1–68 index=966, Table 6, Line 15)

Trend investment cost: $115,000,000

Annual Costs:

Fixed charges on $115,000,000 @ 3.81%------------------	$4, 380, 000
Annual O&M @ $2.90/kw/yr---	290, 000
Recreation fixed charges and O&M @ $ incl/acre/yr------	---------
Total annual costs---------	4, 670, 000

Annual Values:

Power:

Capacity of 100,000 kw @ $10.80/kw/yr ----------	$1, 080, 000
Energy of 273×10^6 kwh @ 2.65 mills--------------	723, 000
Recreation 59,000 acres @ $22.00/acre/year -------	1, 298, 000
Total annual values---	3, 101, 000

Relative feasibility index=0.66 considering power and recreation only

References:

U.S. Study Commission Report, 1963

FPC Form 557 dated 11–65

HD 658, 78th Congress, 2nd Session

FPC Planning Status Report, Savannah River Basin, 1964

FPC Staff testimony on Project No. 2503

Remarks: None

Development: Anthony Shoals

River Basin: Savannah

River: Broad (Ga.)

Capacity: 100,000 kw

Average annual energy: 58.5×10^6 kwh

Reservoir surface area: 14,400 acres

Estimated investment cost: $42,330,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1969; HW index then 811

Ratio HW indexes: 1.190 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $50,400,000

Annual Costs:

Fixed charges on $50,400,000 @ 3.81% --------------------	$1, 915, 000
Annual O&M @ $2.90 /kw/yr--	290, 000
Recreation fixed charges and O&M @ $ incl/acre/yr------	---------
Total annual costs---------	2, 205, 000

Annual Values:

Power:

Capacity of 100,000 kw @ $10.80/kw/yr ----------	$1, 080, 000
Energy of 58.5×10^6 kwh @ 2.65 mills--------------	155, 000
Recreation 14,400 acres @ $41.50/acre/year -------	598, 000
Total annual values---	1, 833, 000

Relative feasibility index=0.83 considering power and recreation only

References:

U.S. Study Commission Report, 1963

FPC Form 557 dated 12–65

HD 658, 78th Congress, 2nd Session

FPC Planning Status Report, Savannah River Basin, 1964

FPC Staff Testimony on Project No. 2503

Remarks: None

11 Development: Tallow Hill

River Basin: Savannah

River: Broad (Ga.)

Capacity: 172,000 kw

Average annual energy: 113×10^6 kwh

Reservoir surface area: 18,500 acres

Estimated investment cost: $78,750,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1960; HW index then 811

Ratio HW indexes: 1.190 (1–1–68 index =966, Table 6, Line 15)
Trended investment cost: $93,600,000

Annual Costs:

Fixed charges on $93,600,000 @ 3.81%	$3, 570, 000
Annual O&M @ $2.63/kw/yr	452, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	4, 022, 000

Annual Values:

Power:

Capacity of 172,000 kw @ $10.80/kw/yr	$1, 858, 000
Energy of 113×10^6 kwh @ 2.65 mills	299, 000
Recreation 18,500 acres @ $38.25/acre/year	708, 000
Total annual values	2, 865, 000

Relative feasibility index=0.71 considering power and recreation only

References:

U.S. Study Commission Report, 1963
FPC Form 557, dated 12–65
HD 658, 78th Congress, 2nd Session
FPC Planning Status Report, Savannah River Basin, 1964
FPC Staff Testimony on Project No. 2503

Remarks: None

12 Development: Trotters Shoals
River Basin: Savannah
River: Savannah
Capacity: 310,000 kw
Average annual energy: 471.4×10^6 kwh
Reservoir surface area: 21,800 acres
Estimated investment cost: $91,927,000
Source of estimate: C of E 3–25–65 report plus interest during construction
Date of estimate: Early 1965; HW index then 879
Ratio HW indexes: 1.096 (1–1–68 index= 966, Table 6, Line 15)
Trended investment cost: $100,600,000

Annual Costs:

Fixed charges on $100,600,000 @ 3.81%	$3, 830, 000
Annual O&M @ $2.48/kw/yr	769, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	4, 599, 000

Annual Values:

Power:

Capacity of 310,000 kw @ $10.80/kw/yr	$3, 348, 000
Energy of 471.4×10^6 kwh @ 2.65 mills	1, 249, 000
Recreation 21,800 acres @ $36.50/acre/year	796, 000
Total annual values	5, 393, 000

Relative feasibility index=1.17 considering power and recreation only

References:

C of E Review Report 2–62
C of E Economic Study Report 3–25–65
U.S. Study Commission Report, 1963
FPC Form 557 dated 11–1965
HD 658, 78th Congress, 2nd Session
FPC Planning Status Report, Savannah River Basin, 1964
FPC Staff Testimony on Project No. 2503

Remarks: Authorized by Congress in 1966

13 Development: Hartwell (Unit No. 5)
River Basin: Savannah
River: Savannah
Capacity: 66,000 kw
Average annual energy: 0 kwh
Reservoir surface area: 0 acres
Estimated investment cost: $2,640,000
Source of estimate: $40/kw for machinery
Date of estimate: Mid-1967; HW index then 946
Ratio HW indexes: 1.021 (1–1–68 index= 966, Table 6, Line 15)
Trended investment cost: $2,700,000

Annual Costs:

Fixed charges on $2,700,000 @ 4.673%	$126, 000
Annual O&M @ $2.00/kw/yr	120, 000
Recreation fixed charges and O&M @ $0/acre/yr	0
Total annual costs	246, 000

Annual Values:

Power:

Capacity of 66,000 kw @ $10.80/kw/yr	$713, 000
Energy of 0 kwh @ 0 mills	0
Recreation 0 acres @ $0/acre/year	0
Total annual values	713, 000

Relative feasibility index=2.90 considering power and recreation only

References:

U.S. Study Commission Report, 1963
FPC Form 557 dated 11–65
HD 658, 78th Congress, 2nd Session
FPC Planning Status Report, Savannah River Basin, 1964
FPC Staff testimony on Project No. 2503

Remarks: None

14 Development: Four Chattooga Developments
River Basin: Savannah
River: Chattooga
Capacity: 186,000 kw
Average annual energy: 245.6×10^6 kwh
Reservoir surface area: 3,738 acres
Estimated investment cost: $137,067,000

Source of estimate: FPC Form 557
Date of estimate: Mid-1960; HW index then 811
Ratio HW indexes: 1.190 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $163,200,000

Annual Costs:

Fixed charges on $163,200,000 @ 3.81%	$6, 220, 000
Annual O&M @ $2.60/kw/yr	484, 000
Recreation fixed charges and O&M @ $27/acre/yr	101, 000
Total annual costs	6, 805, 000

Annual Values:

Power:

Capacity of 186,000 kw @ $10.80/kw/yr	$2, 009, 000
Energy of 245.6×10^6 kwh @ 2.65 mills	651, 000
Recreation 3,738 acres @ $53/acre/yr	198, 000
Total annual values	2, 858, 000

Relative feasibility index=0.42 considering power and recreation only

References:

FPC Form 557 of 12–67
U.S. Study Commission Report, 1963
HD 658, 78th Congress, 2nd Session
FPC Planning Status Report, Savannah River Basin, 1964
FPC Staff testimony on Project No. 2503

Remarks: Camp Creek, Rogues Ford, Sand Bottom and War Woman have 93,000 acre feet aggregate usable power storage, of which 83,000 acre feet are in the upper development, War Woman. With this limited storage, combined capacity of four projects is estimated at 186,000 kw at 15% average annual capacity factor. Capacity contemplated (366,000 kw) in U.S. Study Commission's Report is without adequate accompanying energy

15 Development: Ohoopee-Goose Creek
River Basin: Altamaha
River: Altamaha
Capacity: 169,000 kw
Average annual energy: 295.8×10^6 kwh
Reservoir surface area: 44,600 acres
Estimated investment cost: $145,206,000

Source of estimate: C of E Review Report 5–65
Date of estimate: Mid-1963; HW index then 853
Ratio HW indexes: 1.133 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $164,600,000

Annual Costs:

Fixed charges on $164,600,000 @ 3.81%	$6, 260, 000
Annual O&M @ $2.63/kw/yr	444, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	6, 704, 000

Annual Values:

Power:

Capacity of 169,000 kw @ $10.80/kw/yr	$1, 825, 000
Energy of 295.8×10^6 kwh @ 2.65 mills	784, 000
Recreation 44,600 acres @ $26.00/acre/year	1, 160, 000
Total annual values	3, 769, 000

Relative feasibity index=0.56 considering power and recreation only

References:

U.S. Study Commission Report, 1963
FPC Form 557 of 12–65
C of E Review Report 5–65
FPC Planning Status Report, Altamaha River Basin 1964

Remarks: Powerplant at Goose Creek dam and reservoir connected by a 24-mile canal with Ohoopee dam and reservoir, river mile 102.3

16 Development: Laurens Shoals
River Basin: Altamaha
River: Oconee
Capacity: 324,000 kw (includes 216,000 kw reversible)
Average annual energy: 341×10^6 kwh (298×10^6 kwh pumping input energy) @ 3.7 mills $1,102,-000
Reservoir surface area: 38,700 acres
Estimated investment cost: $46,567,000
Source of estimate: Ga. Power Co. License Application
Date of estimate: Current
Ratio HW indexes: — (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $0
Annual Costs:

Fixed charges on $46,567,000 @ 3.81%	$1, 775, 000
Annual O&M @ $2.47/kw/yr plus $1,102,000 pumping energy	1, 943, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	3, 718, 000

Annual Values:
Power:

Capacity of 324,000 kw @ $10.80/kw/yr	$3, 500, 000
Energy of 341×10^6 kwh @ 2.65 mills	904, 000
Recreation 38,700 acres @ $28.20/acre/year	1, 088, 000
Total annual values	5, 492, 000

Relative feasibility index=1.48 considering power and recreation only
References: Georgia Power Company's Application for FPC License
Remarks: In addition, values include use of reservoir for cooling water by Georgia Power Company, thus enhancing benefit/cost ratio

17 Development: Coopers Ferry
River Basin: Altamaha
River: Ocmulgee
Capacity: 120,000 kw
Average annual energy: 188.6×10^6 kwh
Reservoir surface area: 66,900 acres
Estimated investment cost: $87,667,000
Source of estimate: C of E Review Report 5–65
Date of estimate: Mid-1963; HW index then 853
Ratio HW indexes: 1.133 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $99,400,000
Annual Costs:

Fixed charges on $99,400,000 @ 3.81%	$3, 790, 000
Annual O&M @ $2.80/kw/yr	336, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	—
Total annual costs	4, 126, 000

Annual Values:
Power:

Capacity of 120,000 kw @ $10.80/kw/yr	$1, 296, 000
Energy of 188.6×10^6 kwh @ 2.65 mills	500, 000
Recreation 66,900 acres @ $20/acre/yr	1, 338, 000
Total annual values	3, 134, 000

Relative feasibility index=0.76 considering power and recreation only
References:
U.S. Study Commission Report, 1963
FPC Form 556 of 12–65
C of E Review Report 5–65
FPC Planning Status Report, Altamaha River Basin 1964
Remarks: None

18 Development: Spewrell Bluff
River Basin: Apalachicola
River: Flint
Capacity: 100,000 kw
Average annual energy: 133×10^6 kwh
Reservoir surface area: 16,800 acres
Estimated investment cost: $68,448,000
Source of estimate: FPC Form 557
Date of estimate: Mid-1961; HW index then 814
Ratio HW indexes: 1.188 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $81,300,000
Annual Costs:

Fixed charges on $81,300,000 @ 3.81%	$3, 095, 000
Annual O&M @ $2.90/kw/yr	290, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	3, 385, 000

Annual Values:

Power:

Capacity of 100,000 kw @ $10.80/kw/yr ---------- $1,080,000

Energy of 133×10^6 kwh @ 2.65 mills-------------- 352,000

Recreation 16,800 acres @ $39.50/acre/yr ------- 664,000

Total annual values------ 2,096,000

Relative feasibility index=0.62 considering power and recreation only

References:

FPC Form 557 12–67

C of E Report 2–28–62

U.S. Study Commission Report 1963

FPC Planning Status Report, Apalachicola River Basin, 1965

Remarks: None

19 Development: Smiths Ford

River Basin: Tombigbee

River: Locust Fork

Capacity: 115,200 kw

Average annual energy: 84.3×10^6 kwh

Reservoir surface area: 10,000 acres

Estimated investment cost: $51,680,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1965; HW index then 887

Ratio HW indexes: 1.09 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $56,400,000

Annual Costs:

Fixed charges on $56,400,000 @ 3.81% -------------------- $2,145,000

Annual O&M @ $2.87/kw/yr--- 331,000

Recreation fixed charges and O&M @ $20.50/acre/yr----- 205,000

Total annual costs--------- 2,681,000

Annual Values:

Power:

Capacity of 115,200 kw @ $10.80/kw/yr ---------- $1,245,000

Energy of 84.3×10^6 kwh @ 2.65 mills-------------- 223,000

Recreation 10,000 acres @ $45.60/acre/year ------- 456,000

Total annual values--- 1,924,000

Relative feasibility index=0.72 considering power and recreation only

References:

FPC Form 557 of 1–2–68

Fargo Engineering Co. Report

Remarks: FPC License No. 2102 issued to Warrior River Electric Coop in 1955 for 50-year term. After minor clearing of damsite, construction was suspended. Licensee has recently proposed to surrender license

20 Development: Bridgeview

River Basin: Alabama

River: Tallapoosa

Capacity: 105,000 kw

Average annual energy: 130×10^6 kwh

Reservoir surface area: 8,000 acres

Estimated investment cost: $63,015,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1963; HW index then 853

Ratio HW indexes: 1.133 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $71,500,000

Annual Costs:

Fixed charges on $71,500,000 @ 3.81% -------------------- $2,720,000

Annual O&M @ $2.88/kw/yr-- 302,000

Recreation fixed charges and O&M @ $22.50/acre/yr----- 180,000

Total annual costs--------- 3,202,000

Annual Values:

Power:

Capacity of 105,000 kw @ $10.80/kw/yr ---------- $1,134,000

Energy of 130×10^6 kwh @ 2.65 mills-------------- 345,000

Recreation 8,000 acres @ $57/acre/yr ----------- 446,000

Total annual values--- 1,945,000

Relative feasibility index=0.61 considering power and recreation only

References:

FPC, Tallapoosa River Water Resources Appraisal Report, 1964

FPC Form 557 of 11–65

Remarks: None

21 Development: Martin

River Basin: Alabama

River: Tallapoosa

Capacity: 171,000 kw

Average annual energy: 21×10^6 kwh

Reservoir surface area: No additional acres

Estimated investment cost: $18,650,000

Source of estimate: FPC Form 557

Date of estimate: Mid-1963; HW index then 853

Ratio HW indexes: 1.133 (1–1–68 index =966, Table 6, Line 15)

Trended investment cost: $21,150,000

Annual Costs:

Fixed charges on $21,150,000 @ 4.67%	$988, 000
Annual O&M @ $1.00/kw/yr	171, 000
Recreation fixed charges and O&M @ $ —/acre/yr	---------
Total annual costs	1, 159, 000

Annual Values:

Power:

Capacity of 171,000 kw @ $10.80/kw/yr	$1,850,000
Energy of 21×10^6 kwh @ 2.65 mills	56, 000
Recreation — acres @ $ —/acre/year	---------
Total annual values	1, 906, 000

Relative feasibility index=1.65 considering power and recreation only

References:

FPC, Tallapoosa River Water Resources Appraisal Report, 1964

FPC Form 557 of 11–65

Alabama Power Company FPC Form 12

Remarks: Existing project of Alabama Power Company, additional units in second powerhouse with increased capacity which may require use of storage in proposed Oakfuskee development

22 Development: Emuckfaw

River Basin: Alabama

River: Tallapoosa

Capacity: 181,000 kw

Average annual energy: 196×10^6 kwh

Reservoir surface area: 18,500 acres

Estimated investment cost: $51,253,000

Source of estimate: FPC Appraisal Report

Date of estimate: Mid-1963; HW index then 853

Ratio HW indexes: 1.133 (1–1–68 index= 966, Table 6, Line 15)

Trended investment cost: $58,100,000

Annual Costs:

Fixed charges on $58,100,000 @ 3.81%	$2, 215, 000
Annual O&M @ $2.60/kw/yr	470, 000
Recreation fixed charges and O&M @ $14.50/acre/yr	268, 000
Total annual costs	2, 953, 000

Annual Values:

Power:

Capacity of 181,000 kw @ $10.80/kw/yr	$1, 955, 000
Energy of 196×10^6 kwh @ 2.65 mills	519, 000
Recreation 18,500 acres @ $38.50/acre/year	712, 000
Total annual values	3, 186, 000

Relative feasibility index=1.08 considering power and recreation only

References:

FPC Form 557 of 11–65

FPC, Tallapoosa River Water Resources Appraisal Report, 1964

Remarks: Emuckfaw reservoir would inundate the Horseshoe Bend National Military Park. The upstream alternative Eagle Creek development that would avoid flooding the park has an estimated relative feasibility index of 0.86

23 Development: Crooked Creek

River Basin: Alabama

River: Tallapoosa

Capacity: 135,000 kw

Average annual energy: 149×10^6 kwh

Reservoir surface area: 9,500 acres

Estimated investment cost: $38,073,000

Source of estimate: FPC Appraisal Report

Date of estimate: Mid-1963; HW index then 853

Ratio HW indexes: 1.133 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $43,200,000

Annual Costs:

Fixed charges on $43,200,000 @ 3.81%	$1, 647, 000
Annual O&M @ $2.73/kw/yr	368, 000
Recreation fixed charges and O&M @ $21/acre/yr	200, 000
Total annual costs	2, 215, 000

Annual Values:

Power:

Capacity of 135,000 kw @ $10.80/kw/yr ---------- $1,458,000

Energy of 149×10^6 kwh @ 2.65 mills-------------- 395,000

Recreation 9,500 acres @ $46.40/acre/year ------- 440,000

Total annual values--- 2,293,000

Relative feasibility index=1.04 considering power and recreation only

References:

FPC Form 557 of 11–65

FPC, Tallapoosa River Water Resources Appraisal Report, 1964

Remarks: Preliminary permit issued to Alabama Power Company

24 Development: Mitchell

River Basin: Alabama

River: Coosa

Capacity: 60,000 kw

Average annual energy: 127×10^6 kwh

Reservoir surface area: No additional acres

Estimated investment cost: $15,000,000

Source of estimate: Alabama Power Co.

Date of estimate: 1968; HW index then —

Ratio HW indexes: — (1–1–68 index = 966, Table 6, Line 15)

Trended investment cost: $15,000,000

Annual Costs:

Fixed charges on $15,000,000 @ 4.67% -------------------- $1,700,000

Annual O&M @ $2.00/kw/yr-- 120,000

Recreation fixed charges and O&M @ $0/acr/yr-------- 0

Total annual costs----------- 1,820,000

Annual Values:

Power:

Capacity of 60,000 kw @ $10.80/kw/yr ---------- $ 648,000

Energy of 127×10^6 kwh @ 2.65 mills-------------- 337,000

Recreation 0 acres @ $0/acre/year ------------ 0

Total annual values------ 985,000

Relative feasibility index=1.20 considering power and recreation only

References: Alabama Power Company Project No. 82 Report to the Federal Power Commission, July 1967

Remarks: Existing project, addition of 2-unit powerhouse

25 Development: Sugar Creek

River Basin: Tennessee

River: Elk

Capacity: 100,000 kw

Average annual energy: 140×10^6 kwh

Reservoir surface area: not available acres

Estimated investment cost: $90,000,000

Source of estimate: TVA

Date of estimate: 1–1–62; HW index then 818

Ratio HW indexes: 1.18 (1–1–68 index=966, Table 6, Line 15)

Trended investment cost: $106,100,000

Annual Costs:

Fixed charges on $106,100,000 @ 3.81% -------------------- $4,050,000

Annual O&M @ $2.90/kw/yr--- 290,000

Recreation fixed charges and O&M @ $ incl/acre/yr---- ---------

Total annual costs----------- 4,340,000

Annual Values:

Power:

Capacity of 100,000 kw @ $10.80/kw/yr ---------- $1,080,000

Energy of 140×10^6 kwh @ 2.65 mills-------------- 371,000

Recreation 20,000+ acres @ $38/acre/yr ---------- 760,000

Total annual values----- 2,211,000

Relative feasibility index=0.51 considering power and recreation only

References:

FPC Form 557 of 11–65

FPC Planning Status Report, Tennessee River Basin, 1966

Remarks: Other potential purposes: Flood control, navigation

26 Development: Tellico

River Basin: Tennessee

River: Little Tennessee

Capacity: 135,000 kw

Average annual energy: 228×10^6 kwh

Reservoir surface area: Not available

Estimated investment cost: $52,000,000
Source of estimate: FPC Form 557
Date of estimate: 1–1–62; HW index then 818
Ratio HW indexes: 1.18 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $61,400,000

Annual Costs:

Fixed charges on $61,400,000 @ 3.81%	$2, 340, 000
Annual O&M @$2.73/kw/yr	368, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	2, 708, 000

Annual Values:

Power:

Capacity of 135,000 kw @ $10.80/kw/yr	$1, 458, 000
Energy of 228×10^6 kwh @ 2.65 mills	604, 000
Recreation 15,000±acres @ $41/acre/year	615, 000
Total annual values	2, 677, 000

Relative feasibility index=0.98 considering power and recreation only
References: FPC Form 557 (undated)
Remarks: Navigation and flood control also potential purposes. Project was discarded from potential projects listed in FPC Planning Status Report, Tennessee River Basin, 1966

Development: Devils Jumps
River Basin: Cumberland
River: Big South Fork
Capacity: 480,000 kw
Average annual energy: 475×10^6 kwh
Reservoir surface area: 34,210 acres
Estimated investment cost: $171,635,000
Source of estimate: FPC Form 557
Date of estimate: Mid-1958; HW index then 764
Ratio HW indexes: 1.27 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $217,300,000

Annual Costs:

Fixed charges on $217,300,000 @ 3.81%	$8, 280, 000
Annual O&M @ $2.36/kw/yr	1, 132, 000
Recreation fixed charges and O&M @ $8.25/acre/yr	282, 000
Total annual costs	9, 694, 000

Annual Values:

Power:

Capacity of 480,000 kw @ $10.80/kw/yr	$5, 180, 000
Energy of 475×10^6 kwh @ 2.65 mills	1, 260, 000
Recreation 34,210 acres @ $30/acre/year	1, 025, 000
Total annual values	7, 465, 000

Relative feasibility index=0.77 considering power and recreation only
References:
FPC Form 557 of 11–65
C of E Review Report, Big South Fork, 1958
FPC Planning Status Report, Cumberland River Basin, 1964
Remarks: Other potential purpose: Flood control

Development: Cumberland Falls-Jellico
River Basin: Cumberland
River: Cumberland
Capacity: 145,000 kw plus 90,000 kw pumped storage
Average annual energy: 355,000,000 kwh less 150,000,000 kwh pumping input
Reservoir surface area: 12,520 acres
Estimated investment cost: $84,214,300
Source of estimate: C of E Survey Report 1964
Date of estimate: July 1964; HW index then 871
Ratio HW indexes: 1.11 (1–1–68 index=966, Table 6, Line 15)
Trended investment cost: $93,500,000

Annual Costs:

Fixed charges on $93,500,000 @ 3.81%	$3, 560, 000
Annual O&M @ $2.53/kw/yr	1, 195, 000
Recreation fixed charges and O&M @ $ incl/acre/yr	---------
Total annual costs	4, 755, 000

Annual Values:

Power:

Capacity of 235,000 kw @ $10.80/kw/yr	$2, 540, 000
Energy of 355×10^6 kwh @ 2.65 mills	940, 000
Recreation 12,520 acres @ $43.50/acre/yr	533, 000
Total annual values	4, 013, 000

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Relative feasibility index=0.84 considering power and recreation only

References:

C of E Survey Report 1964

FPC Form 557 of 1–68

FPC Planning Status Report, Cumberland River Basin, 1964

Remarks: Two separate developments now considered as one with Cumberland Falls reservoir serving as lower pool for 2 reversible machines proposed for Jellico Creek development

APPENDIX D—DEFINITION OF BITUMINOUS COAL AND LIGNITE PRODUCING DISTRICTS

DISTRICT 1.—EASTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All east of the Allegheny River, and those mines served by the Pittsburgh & Shawmut Railroad located on the west bank of the river.

Fayette County (part).—All mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines not served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines served by the Pennsylvania Railroad from Torrence, east.

All mines in the following counties: Bedford, Blair, Bradford, Cambria, Cameron, Centre, Clarion, Clearfield, Clinton, Elk, Forest, Fulton, Huntingdon, Jefferson, Lycoming, McKean, Mifflin, Potter, Somerset and Tioga.

Maryland.—All mines in the State.

West Virginia.—All mines in the following counties: Grant, Mineral and Tucker.

DISTRICT 2.—WESTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All mines west of the Allegheny River except those mines served by the Pittsburgh & Shawmut Railroad.

Fayette County (part).—All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines except those served by the Pennsylvania Railroad from Torrence, east.

All mines in the following counties: Allegheny, Beaver, Butler, Greene, Lawrence, Mercer, Venango, and Washington.

DISTRICT 3.—
NORTHERN WEST VIRGINIA

West Virginia.—Nicholas County (part).—All mines served by or north of the Baltimore & Ohio Railroad.

All mines in the following counties: Barbour, Braxton, Calhoun, Doddridge, Gilmer, Harrison, Jackson, Lewis, Marion, Monongalia Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tyler, Upshur, Webster, Wetzel, Wirt, and Wood.

DISTRICT 4.—OHIO

All mines in the State.

DISTRICT 5.—MICHIGAN

All mines in the State.

DISTRICT 6.—PANHANDLE

West Virginia.—All mines in the following counties: Brooke, Hancock, Marshall, and Ohio.

DISTRICT 7.—SOUTHERN NO. 1

West Virginia.—Fayette County (part).—All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake & Ohio Railroad and mines served by the Virginian Railway.

McDowell County (part).—All mines in that portion of the county served by the Dry Fork Branch of the Norfolk & Western Railroad and east thereof.

Raleigh County (part).—All mines except those on the Coal River Branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the main line and the Glen Rogers branch of the Virginian Railway.

All mines in the following counties: Greenbrier, Mercer, Monroe, Pocahontas, and Summers.

Virginia.—Buchanan County (part).—All mines in that portion of the county served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad and in that portion on the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek).

Tazewell County (part).—All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to

Boissevain branch of the Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Montgomery, Pulaski, Wythe, Giles, and Craig.

DISTRICT 8.—SOUTHERN NO. 2

West Virginia.—Fayette County (part).—All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake & Ohio Railroad.

McDowell County (part).—All mines west of and not served by the Dry Fork branch of the Norfolk & Western Railroad.

Nicholas County (part).—All mines in that part of the county south of and not served by the Baltimore & Ohio Railroad.

Raleigh County (part).—All mines on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway and lying west of the mouth of Skin Fork of Guyandot River.

All mines in the following counties: Boone, Cabell, Clay, Kanawha, Lincoln, Logan, Mason, Mingo, Putnam, and Wayne.

Virginia.—Buchanan County (part).—All mines in the county, except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

Tazewell County (part).—All mines in the county except in those portions served by the Dry Fork branch of the Norfolk & Western Railroad and branch from Bluestone Junction to Boissevain of Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Dickinson, Lee, Russell, Scott, and Wise.

Kentucky.—All mines in the following counties in eastern Kentucky: Bell, Boyd, Breatbitt, Carter, Clay, Elliott, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Leslie, Letcher, McCreary, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Wayne, and Whitley.

Tennessee.—All mines in the following counties: Anderson, Campbell, Claiborne, Cumberland, Fentress, Morgan, Overton, Roane, and Scott.

North Carolina.—All mines in the State.

DISTRICT 9.—WEST KENTUCKY

Kentucky.—All mines in the following counties in western Kentucky: Butler, Christian, Crittenden, Daviess, Hancock, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Simpson, Todd, Union, Warren, and Webster.

DISTRICT 10.—ILLINOIS

All mines in the State.

DISTRICT 11.—INDIANA

All mines in the State.

DISTRICT 12.—IOWA

All mines in the State.

DISTRICT 13.—SOUTHEASTERN

Alabama.—All mines in the State.

Georgia.—All mines in the following counties: Dade and Walker.

Tennessee.—All mines in the following counties: Bledsoe, Grundy, Hamilton, Marion, McMinn, Rhea, Sequatchie, Van Buren, Warren, and White.

DISTRICT 14.—ARKANSAS-OKLAHOMA

Arkansas.—All mines in the State.

Oklahoma.—All mines in the following counties: Haskell, Le Flore, and Sequoyah.

DISTRICT 15.—SOUTHWESTERN

Kansas.—All mines in the State.

Texas.—All mines in the State.

Missouri.—All mines in the State.

Oklahoma.—All mines in the following counties: Coal, Craig, Latimer, Muskogee, Okmulgee, Pittsburg, Rogers, Tulsa, and Wagoner.

DISTRICT 16.—NORTHERN COLORADO

All mines in the following counties in the State: Adams, Arapahoe, Boulder, Douglas, Elbert, El Paso, Jackson, Jefferson, Larimer, and Weld.

DISTRICT 17.—SOUTHERN COLORADO

Colorado.—All mines except those included in District 16.

New Mexico.—All mines except those included in District 18.

DISTRICT 18.—NEW MEXICO

New Mexico.—All mines in the following counties: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miguel, Santa Fe, and Socorro.

Arizona.—All mines in the State.
California.—All mines in the State.

DISTRICT 19.—WYOMING

Wyoming.—All mines in the State.
Idaho.—All mines in the State.

DISTRICT 20.—UTAH

All mines in the State.

DISTRICT 21.—NORTH DAKOTA-SOUTH DAKOTA

All mines in North Dakota and South Dakota.

DISTRICT 22.—MONTANA

All mines in the State.

DISTRICT 23.—WASHINGTON

Washington.—All mines in the State.
Oregon.—All mines in the State.
Alaska.—All mines in the State.

FUEL RESOURCES, REQUIREMENTS AND COSTS FOR ELECTRIC GENERATION IN EASTERN UNITED STATES

REPORT OF

THE FOSSIL FUEL RESOURCES COMMITTEE

NORTHEAST, EAST CENTRAL AND SOUTHEAST REGIONS

TO THE FEDERAL POWER COMMISSION

MAY 1968

PREFACE

Work on the preparation of this report began when the Fossil Fuel Resources Committee met for the first time in June of 1967. Basic research was completed early in 1968, and drafting of the report was concluded in April of the same year.

The focal point of the report was a questionnaire on expected fuel requirements, which was designed by the Committee and mailed in the fall of 1967 to all electric power systems having a peak demand in excess of 50 megawatts in the 24 states of the Eastern United States and the District of Columbia. The questionnaire and the data obtained from it are described in greater detail in Part III of this report. The Fuels Committee survey was conducted independently of and prior to surveys conducted by the Task Forces on Load Projection and the Task Forces on Patterns of Generation and Transmission. The latter surveys indicate a slower rate of growth of nuclear generation, particularly in the East Central Region.

The statistical tables presented in this report which reflect future projections are the sum total of the projections provided by the individual systems to the Committee in response to the questionnaire, rather than estimates by the Committee. The Committee assembled the information and provided the historical and economic background for past developments, as well as discussions of indicated trends. This report, therefore, is essentially a reflection of the future fossil fuel supply and demand picture as seen by the utility users in the winter of 1967–68.

Since this report was completed for submission to the Federal Power Commission for eventual inclusion in the updated National Power Survey, much has happened. Use of electric power increased more rapidly than expected. Nuclear power delays showed up. Air pollution control programs accelerated. Rail freight and coal costs went up. Residual fuel oil prices went down markedly, and more low sulfur fuel oil became available. As a result, electric utility fossil fuel consumption figures for 1967 and preliminary figures for 1968, which have now become available, show that some of the fuel usage deviated significantly from that initially presented in this report.

The following tabulation, taken from Table 5 of the report covers the Northeast and Southeast Regions and is supplemented by actual figures of fuel consumption by electric utilities in those regions for the years 1967 and 1968.

Consumption of Fuels [1]

[From Table 5, except for 1967 and 1968]

Year	Northeast region			Southeast region		
	Coal	Oil	Gas	Coal	Oil	Gas
			Actual Consumption			
1966.....	57.9	[2] 76.5	100.2	63.2	[2] 28.0	140.8
1967 [3]....	56.6	[2] 101.2	115.0	62.6	[2] 31.3	168.0
1968 [3]....	57.4	[2] 120.4	138.0	72.0	[2] 35.7	232.0
			Industry Forecast			
1970.....	63.0	69.5	148.5	84.6	22.6	218.4
1975.....	61.8	57.4	162.4	95.4	19.1	214.8
1980.....	56.8	47.8	146.6	99.6	18.9	229.3
1985.....	48.8	41.3	129.1	108.4	19.8	340.2
1990.....	40.6	37.5	117.5	121.5	18.7	422.2

[1] Fuel quantities in millions of tons of coal, barrels of oil, and MCF of gas.

[2] Includes small quantities of distillates.

[3] Actual data published by FPC subsequent to completion of the report.

From the above figures it is evident that, at least for the short term, fuel oil consumption in the Northeast and Southeast Regions has taken a decided upward trend. Furthermore, natural gas consumption in the Southeast for 1968 has already exceeded the annual usage rates predicted for the period 1970–1980. Some of the reasons explaining these newly indicated trends have been noted above, and are discussed more fully below.

1. *Growth of electric power generation*

After a less-than-average growth of electric power production in 1967 (as compared with 1966), total U.S. electric power output in 1968 gained 9.3 percent over 1967. In 1968, power output by fuel-burning plants in the U.S. was 11.3 percent higher than the previous year. This accelerated growth, which was particularly evident in the Southeast Region, has created unusual demands for all types of fuel for electric power generation.

2. *Difficulties in nuclear generation*

A number of recent problems tend to delay and to increase the cost of nuclear plant construction and, consequently, to increase the cost of nuclear power. Among these problems are: Delays in licensing; environmental restrictions (e.g. thermal pollution); siting problems near load centers; increasing construction lead times; and rapidly increasing capital costs. The overall effect of the increase in nuclear power costs, as compared with lower increases in fossil fueled plant costs, is to improve the competitive position of fossil fueled plants.

3. *Accelerated programs of air pollution control*

Although electric power system management has understood the meaning and objectives of air pollution control legislation, it hoped that reasonable and adequate periods of time would be allowed for normal development of low-sulfur technology or, alternatively, for the orderly development of a low-sulfur fuels market. Vigorous pursuance of air pollution controls has created unforeseen price pressures on some of the fossil fuels and resulted in somewhat different than anticipated patterns of energy consumption.

Significant quantities of low-sulfur residual fuel oil derived from African crude oils have recently become available at competitive prices. This paraffin base oil is being blended with western hemisphere residual oils and number 2 and number 4 distillate to yield a low-sulfur product with an acceptable pour point. The availability of low-sulfur residual fuel oil may be further improved with the completion of desulfurizing facilities in a number of Caribbean refineries, including several that process Venezuelan crude. Oil import permits have recently been granted to three organizations for the purpose of domestic desulfurization into low-sulfur fuel acceptable to the air pollution control agencies. The new supply of low-sulfur oil has eased the problem of supplying those areas which have enacted sulfur-content restrictions on residual fuel oils.

Most types of residual fuel oil can now be delivered at favorable prices, particularly when purchased in large lots and on intermediate-to-long range contracts (5 years or longer), for delivery in large vessels. Most of these contracts have escape clauses for changes in sulfur regulations.

4. *Increasing mine price of coal*

The United Mine Workers have recently negotiated a new work contract which provided for wage increases in each of the three years covered by the contract. In addition, the cost of equipment and materials has also increased. While some of the increasing costs may be offset by increases in labor productivity, the net mine price will probably rise in the foreseeable future. Additional pressures on the mine price of coal may also arise from recently proposed health, safety, and environmental control legislation.

5. *Increasing railroad freight rates*

The railroads have requested and have recently been granted across-the-board freight rate increases, including increases on rates for shipments of coal by unit trains. The net effect of this change in freight rates is to increase the delivered cost of coal to electric utilities.

6. *Changes in the residual fuel oil market*

As outlined above, the supply of high-sulfur residual fuel oil relative to the demand on the East Coast has increased in the past two years. First, the threat of sulfur oxides emission regulations has caused many users to shift to low sulfur oil. Particularly, the increased availability and use of African

low-sulfur oil on our East Coast has added to the overall supply of residual oil on the market. Full capacity Caribbean refinery operations are helping to fill the gap for distillate products in Europe (a gap created by the closing of the Suez Canal). All of these factors contribute to the easing of the supply (and, consequently, to the decline in the price) of fuel oil on the East Coast. The near-term outlook is that downward pressure on the price of residual oil will continue to prevail for the following reasons.

Extra Refinery Capacity in Eastern Canada.—Construction of new refinery capacity, at a rate considerably above domestic requirements in anticipation of export markets, has been announced for Nova Scotia. One such market is presumed to be the United States.

Machiasport-type Projects.—There are pending for consideration proposals for a number of projects that can be categorized as Machiasport-type projects. These projects envision importation of foreign crude oil into free trade zones in the United States with the understanding that part of the imports will be marketed in the United States. Such proposals amount to modification of the oil import program and could, if approved, have the effect of bringing larger volumes of foreign residual fuel oil to the power generating industry.

North Slope Petroleum Discoveries.—Large deposits of petroleum have been discovered recently on the North Slope of Alaska. These discoveries have provided the inducement for a more extensive search for petroleum in the Arctic areas of the Western Hemisphere. Although some problems of search, production, and transportation in the cold Arctic areas still have to be resolved, the general outlook is that these new finds will contribute significantly to the domestic supply of refined and, to a much lesser extent, residual products.

Oil Import Program.—In 1966 there was a complete relaxation of restrictions on the import of residual fuel oil on the eastern seaboard. This made foreign residual fuel oil more accessible and accelerated the downward trend in residual fuel oil prices, particularly in the Northeast. To the extent that there is no limit to the amount of residual fuel oil that can be brought into the East Coast area for consumption as fuel, the price of this oil will be largely determined by foreign competition for the U.S. market. It should be noted, however, that a change in the oil import program could have a decisive effect on the availability and price of residual fuel oil to ultimate consumers on the eastern seaboard.

In summary, short term divergencies have already been noted in some areas of the forecast. Whether or not they grow into a long term trend is dependent upon factors, including government policy, which cannot be accurately predicted. As with all other forecasts and estimates, their value lies in developing an understanding of the factors which may influence the course of events, and the degree of change which may occur.

Because the initial figures included in this report present industry's own evaluation and expectations based on information available at the time, the Fossil Fuel Resources Committee felt that there was merit in publishing those figures without change, but including actual usages available for comparison.

The Committee feels that the short range deviations from the predictions tend to underscore a number of important issues:

The volatility of the fossil fuels market;
The difficulties of accurate planning;
The complexity of factors affecting electric utility fuel consumption; and
The caution required in utility forecasts.

FOSSIL FUEL RESOURCES COMMITTEE

Northeast, East Central, and Southeast Regions

MEMBERS

John F. Campbell, Chairman, Consolidated Edison Company of New York, Inc.

Kurt Brenner, Public Service Electric and Gas Company

Earl F. Brush, Hamilton (Ohio) Department of Public Utilities

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William W. Cofield, Office of Oil and Gas, Department of the Interior

John P. Gallagher, Piqua (Ohio) Municipal Plant, previous member of the Committee, resigned due to change of employment

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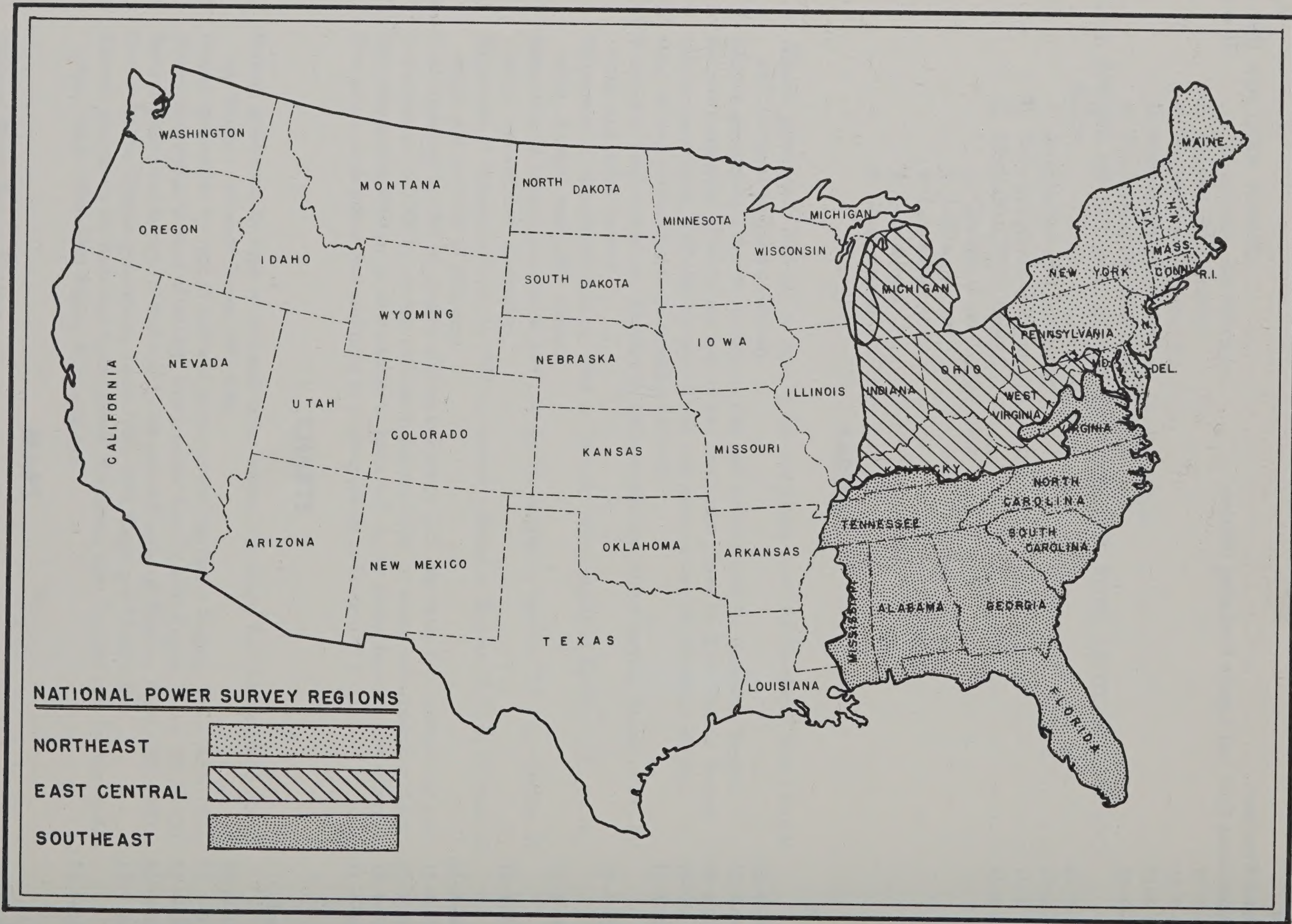

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SOUTHEAST
WASHINGTON
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WYOMING
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I INTRODUCTION

The purpose of this report is to bring up to date studies made for the 1964 National Power Survey (Survey 1964) of the Federal Power Commission, reflecting changes in technology, public policy and energy trends since the original Survey, with particular reference to fuels used for electric generation in the Northeast, East Central and Southeast Regions. Also, this report will seek to extend by another ten years, to 1990, the energy projections in Survey 1964.

In updating Survey 1964 we have not attempted to change or modify the extensive and authoritative background material in that report, which represents the best in advanced thinking on industry fuel problems by some of its foremost members. Instead we have supplemented that report where intervening developments have significantly changed the fuel picture.

Two such developments with respect to fuels for electric generation have assumed pre-eminence in the last few years, namely, air pollution control and nuclear power. The nation's concern about the need for cleaner air is resulting in legislation at federal, state and local levels mandating, among other things, the use of fuels having a progressively decreasing sulfur content to minimize the emission of sulfur dioxide from electric power plants and industrial and residential heating installations, or the use of processes to reduce sulfurous emissions when fuels of higher sulfur content are used. Air pollution abatement will increase power generation costs which ultimately will be reflected in consumer rates, and will necessitate changes in historical fuel patterns as the demand for low-sulfur coal and oil tends to place undue strain on available short-term supplies.

For the longer term, 1971 and thereafter, the problems of air pollution may be reduced through the development of commercial fuel desulfurization techniques and the development of commercial stack emission control systems to supplement the limited supplies of naturally occurring low sulfur fuels. Because natural gas is virtually sulfur-free, its use as boiler fuel is receiving increasing attention by industry and by the Federal Power Commission which must find the public interest in balancing the need for cleaner air against conservation of a depletable national resource.

Nuclear power for electric generation has made and is continuing to make such impressive technological progress that the projections of nuclear's share of the fuel market in Survey 1964 must be revised upward to a marked extent. The commercial development of fast breeder reactors will substantially alleviate the present factor of economically limited nuclear fuel reserves.

Other noteworthy developments include the rising trend in minemouth and midpoint electric plants with EHV transmission to distant load centers; the increasing acceptance of gas turbines and pumped storage for peaking power; "total energy" systems; and technologic progress in coal gasification.

As was true with Survey 1964, this updating could not have been conducted without the public-spirited assistance of all segments of the industry and of other private agencies, and government.

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II SUMMARY AND CONCLUSIONS

The rapid trend toward nuclear generation has resulted in a drastic change in the electric utilities' forecasted fuel uses since publication of the 1964 "National Power Survey." That survey indicated that by 1980 nuclear capability would be supplying 10% of the Nation's KWH generation.[1]

Our current survey indicates that this 10% point will be reached, in the three eastern regions, shortly after 1970, and that nuclear power will account for 46% of the total generation by 1980, and 65% by 1990. This predicted growth is primarily the result of reductions in the installed cost of nuclear units from over $200 per KW in 1964 to generally under $150 per KW in 1968 although, for comparable sizes and construction types, nuclear units will cost from 15% to 20% more than coal fired units in plants of about 800 MW and up range.

These cost reductions have come about from:

(1) Experience gained by the industry in building the nuclear units now operating.

(2) Constantly increasing knowledge of the technologies involved by the manufacturers, the consultants and the utility industry.

(3) Increased competition among the manufacturers.

More recently, quoted prices for nuclear steam supply systems have increased substantially. This component cost increase apparently has not yet been a deterrent to the competitive position of nuclear plants.

The major attraction of nuclear generation is its very low fuel cost, coupled with a practically non-existent fuel transportation cost. The absence of atmospheric pollutants is another advantage. Drawbacks to nuclear generation are:

(1) Restrictions on locating such units close to centers of population—the heavy load centers.

(2) The very large unit sizes necessary to obtain the low installed costs mentioned above.

(3) The need for highly trained, highly paid, and very scarce technical and supervisory personnel.

(4) The necessity for operating at high capacity factors to realize low total costs.

(5) The need for increased volumes of condenser cooling water relative to fossil fuel units.

Current concern about air pollution and the probability of air pollution control regulations in most of the metropolitan areas within the next few years introduces a large element of uncertainty into current fuel use forecasts. However, it seems safe to predict an even higher percentage of nuclear generation, more interest in "mine-mouth" coal-fired plants remote from populated areas, more intensive development of low-sulfur fuel sources and emission control systems, and generally higher energy costs for all electric utilities. These higher costs eventually must be borne by the consuming public.

The choice of fossil fuel to be used in any given generating unit has usually been purely economic—which fuel will result in the lowest cost per Btu produced in the boiler over the life of the unit. The costs to be considered are:

(1) Fuel producer's selling price.

(2) Transportation cost.

(3) User's handling cost.

(4) Conversion efficiency.

To these must now be added a fifth, and at present largely unknown, cost:

(5) Compliance with anti-air pollution ordinances.

On the basis of the industry survey by this Committee, of the three fossil fuels, the use of natural gas for electric power generation in the eastern regions is expected to show the greatest relative increase, from 243 billion cubic feet in 1966 to 545 billion cubic feet in 1990. The use of coal in these regions is also expected to expand substantially, but at a much lower rate than gas, from 203 million tons in 1966 to 331 million tons in 1990. Consequently, the relative position of coal in the total generation of the three eastern regions may decline from about 80

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[1] 1964 National Power Survey, Vol. 2, Advisory Report No. 15, page 177.

percent in 1966 to 29 percent in 1990. During the same period of time the absolute use of fuel oil may decrease from 105 million to 57 million barrels.

The Nation's known coal reserves are more than adequate to meet all the needs of the electric utilities, and all other users, through and well beyond 1990. Slightly over one-half of the Nation's total reserves of bituminous coal are within the three eastern regions covered by this survey, and about one-third of this reserve is in the Appalachian area.

Most of the total reserves of low-sulfur bituminous coal are in this same Appalachian region. However, very large investments will be required for any extensive mining of this coal; it is more costly to mine, it is generally at a greater transportation distance from the points of use than is conventional coal, and there is considerable competition for it from other industries. All of these factors indicate considerably higher delivered costs than for conventional bituminous coal, which will be reflected in electric consumers' rates.

The long-term mine price of coal has trended downward until recently due to mechanization and improved productivity. For the future, however, the results of this Commitee's survey indicate increasing cost of coal at plants for electric generation.

Most electric utility coal moves by rail, and here the development and use of "unit trains" has resulted in important cost savings. Further development of this concept into high speed "shuttle" trains may result in some transportation efficiencies, although rates for coal are increasing at the present time.

The practicality of pipeline transportation of coal has been proven by a 108-mile line which operated successfully for several years. Presently being planned in the far west is a 275-mile coal pipeline, which studies indicate will have total costs competitive with rail transportation. Further developments in pipeline transmission may well change the coal transportation picture considerably.

Water shipments of coal have increased appreciably in recent years and are expected to continue as an important part of overall coal transportation.

Improvements in the technology of, and reductions in the costs of Extra High Voltage (EHV) AC and DC transmission are making the transportation of "coal by wire" more attractive. It appears that within the next few years it will be economically practical to transmit blocks of 3,000–4,000 MW from mine-mouth plants to load areas in the range of 600 to 700 miles distant. This technique may become especially attractive because of the probability of less acute air pollution problems in mining areas than in large metropolitan areas. However, dependence of a metropolitan area for its power supply upon long transmission lines introduces reliability problems in the event of major line outages. Solution of these and other problems appears expensive and may well cancel out part of the savings otherwise possible.

The delivered cost of natural gas to electric utilities has remained relatively stable since 1960. This Committee's survey indicates, however, that such cost is likely to increase. Gas is the easiest and least expensive of all fossil fuels to handle at electric generating stations, and the burning of gas minimizes air pollution problems. The survey indicates that gas will play an increasing role in the generating of electricity, particularly in the Southeast. These predictions are contingent on adequate supplies of natural gas and other factors, including regulatory policy with respect to optimum use of this depleting natural resource.

Technology is available today for shipping large quantities of gas in a liquefied state. Cost studies indicate, however, that it will be some time before liquefied natural gas (LNG) becomes economically attractive to utilities covered by this report.

Fuel oil (residual) has been of importance in power generation only in the coastal area of the Northeast and in the extreme Southeast. The future use of this fuel is contingent on federal import policies and economic factors. Furthermore, domestic refineries now produce more profitable products from crude oil, resulting in less residual production. For these reasons it is expected that few new oil burning utility generating units will be built.

III ELECTRIC ENERGY REQUIREMENTS

A. Introduction

The historical pattern of fuel consumption for electric generation is undergoing significant changes as a result of the nation's concern for cleaner air and the accelerating growth of nuclear power.

In order to outline the general dimensions of this change, a recent questionnaire-type survey was made by this Committee of energy requirements and fuel costs at investor-owned, publicly owned and federal electric power systems in the area of eastern United States covered by this report. The survey, initiated in October 1967, included actual operating experience for the year 1966 and estimates for the period 1970 to 1990, at 5-year intervals.

B. Survey of Fuel Use and Fuel Costs

1. Description and Coverage of Questionnaire Survey

The survey covered electric power systems having peak demands in excess of 50 megawatts in the 24 states and the District of Columbia comprising the Federal Power Commission's Northeast, East Central and Southeast Regions for updating the 1964 National Power Survey. The survey area is shown on Map 1.

Replies to the questionnaire were received from all except a few small companies, although some of the replies were incomplete, particularly as to fuel costs in the future. Estimates of total kilowatt hour generation in the next two decades by respondents to the questionnaire were generally in close agreement with corresponding estimates made by the regional offices of the Federal Power Commission.

2. Summary of Questionnaire Survey Data

Tables 1 to 5 and Charts 1 to 6 summarize the results of the survey with respect to electric generation and fuel requirements in the Northeast, East Central and Southeast Regions during the period 1966 to 1990. Unless otherwise noted, the following brief analysis relates to the foregoing three regions covered by the study.

(a) Electric generation by fuels and hydropower will increase from 618 billion kilowatthours in 1966 to 2,968 billion kilowatthours in 1990, representing a compound annual growth rate of approximately 6.7 percent during the period. The projected growth rates of the respective Regions are: Northeast 6.6%, East Central 6.3% and Southeast 7.2%.

(b) Nuclear energy, a relatively minor factor in 1966, will account for two thirds of electric production in 1990, the percentage varying between 49% in the East Central Region and 82% in the Northeast.

(c) Approximately 63% more coal will be consumed in producing electricity in 1990 than today, but coal's contribution to the fuel mix will drop from 80% to 29% during this period as a result of the growing acceptance of the industrial atom. In 1966, a total of 203 million tons of coal were burned to produce 491 billion kilowatthours; in 1990, it is estimated that 331 million tons will produce 852 billion kilowatthours.

(d) Fuel oil for electric generation is used principally in the Northeast Region wherein annual use during the next two decades is expected to decrease from its 1966 level of 76 million barrels to around 37 million barrels by 1990. For the three regions the respective quantities are 104 million barrels in 1966 and 57 million barrels in 1990.

(e) Natural gas consumed in producing electricity will increase by 124% over current consumption levels to 545 billion cubic feet by 1990. Natural gas will account for only 2% of total electric generation in 1990, compared to 3.9% today.

(f) Conventional type hydro-electric plants in 1966 produced 37 billion kilowatthours or 6% of total generation in Eastern U.S., while pumped storage had only a minor role. Electric production by hydropower is expected to double by 1990, about equally divided between conventional and pumped storage hydro, and will represent some 2.7% of

total generation. These plants will be located mostly in the Northeast and Southeast Regions.

(g) The survey responses on future costs of fossil fuels generally reflect the difficulties attending such long-range estimates. The estimates exhibit wide variations, not always readily accounted for by geographical or other factors influencing costs. A number of companies did not supply this information.[1]

Subject to the foregoing caveat, the following generalizations may be drawn from the survey data with respect to future costs of fuel for electric generation (See Chart 5):

(*i*) The delivered cost of coal, oil and gas in the Northeast and Southeast Regions will increase by about 15% in the next two decades. In the East Central Region, which includes some of the largest coal supplies in the nation, coal prices are expected to be somewhat more stable during this period. Oil and gas have only a minor role in that area.

(*ii*) Coal costs will maintain their competitive position vis-a-vis oil and gas, with a favorable differential of 3–5¢ per million Btu.

(*iii*) Nuclear costs per million Btu, exclusive of carrying charges on the fuel, are estimated to average between 14 cents and 18 cents.

[1] The percent generation for which fuel costs were not supplied is as follows:

	1970	*1975*	*1980*	*1985*	*1990*
Northeast	7	6	17	19	20
East Central	7	12	23	29	31
Southeast	1	19	32	37	40
Combined	5	13	24	29	31

IV COAL

A. Introduction and Summary

As a result of increasing efficiencies in the production, distribution, and transportation of coal, and in its utilization for power generation, coal accounted for approximately 65 percent of fuel consumed by electric utilities in the United States in 1966, on a total Btu basis.

Each year sees increasing quantities of coal used for the thermal generation of power, and it is generally accepted that, quantitatively, the trend will continue upward well beyond the period covered by this revision of the National Power Survey. The question is how it will relate, percentagewise, to other energy sources in response to changes which already are taking place in the energy mix, including the growth of nuclear power generation and growing pressures for the reduction of air pollution.

For the types of coal conventionally used for power generation, recoverable coal reserves are more than adequate to meet all foreseeable requirements far into the future. Reserves of low-sulfur bituminous coals also are substantial. Because of higher mining costs and longer distances for transport, however, the costs of such coals will be higher and their availabilities will differ more or less directly in relation to the levels of sulfur content established in pollution abatement regulations. Furthermore, the characteristics of low-sulfur coal are not always suitable for all types of furnaces.

B. Coal Reserves

Mounting interest in air pollution abatement has added new dimensions to the appraisal of coal reserves, their quality, and their availability for power generation. Principal of these is increased emphasis on coals of low sulfur levels, for the scope of coal availability narrows progressively as sulfur specifications become more restrictive. A corollary factor of importance is higher delivered prices for some of these coals, as compared to coals conventionally used for thermal generation, resulting from both higher mining costs in some production areas and longer transportation distances.

The development of commercial processes for the reduction of sulfur in coal or the removal of sulfur oxides from stack gases will permit the continuing use of medium and higher sulful coals. Indications are that laws and regulations will either (1) restrict the sulfur content of fuels consumed to levels consistent with whatever considerations are pertinent to the respective areas, or (2) establish limitations on the sulfurous content of stack emissions into the atmosphere following combustion.

"Conventional" Coal Availabilities

For the types of coal conventionally used by electric utilities, recoverable coal reserves of the United States are more than ample to meet the demand for power generation during the period of this study, and beyond. Estimated remaining national coal reserves, adjusted for production through 1964, and based on only 50 percent recovery, approximate 788,000 million tons.

Even on the basis of highly selective levels of coal bed thicknesses (3.5 feet or more for bituminous and higher rank coals and 10 feet or more for subbituminous and lower rank coals) it is estimated that from 220,000 million to 265,000 million tons of "known" reserves (400 to 475 years supply at current rates of output) are economically recoverable with established technology. Between 45,000 million and 55,000 million tons of these selective coals are estimated to be "measured" reserves, 65,000 million to 78,000 million tons are "indicated," and 110,000 million to 132,000 million tons are "inferred" reserves. Measured reserves are those for which tonnage was computed from direct measurements. Indicated reserves are those for which tonnage was computed partly from specific measurements and partly from reasonable assumptions based on available data and geologic evidence. Inferred reserves are those for which quantitative estimates are based on a broad knowledge of the character of the bed or region, but for which there are few, if any, actual measurements. In addition to these selective thicknesses of reserves, large additional quantities of "known" recoverable reserves of lesser thicknesses

also are readily available and currently are being mined economically. It is anticipated that by the time other deposits are needed advanced technology will make them available at the same relative economic levels. Also, current investigations by the Bureau of Mines indicate that average recovery in mining is higher than the 50 percent used herein—approximating 57 percent for total underground mining. With respect to the principal reserves from which energy markets in the three regions covered by this report are served, there are further indications that recovery from specific coal beds is at an even higher level—possibly averaging 70 percent—because it is economical to mine more of the higher priced premium coals of the Appalachian region.

1. Regional Distribution of Reserves

Of considerable importance to future power generation, coal-bearing formations are widely distributed throughout the nation (Map 2). On the basis of quantity, about 70 percent of the reserves are west of the Mississippi River. These deposits, however, principally are subbituminous coal and lignite, whereas the eastern coals are bituminous and anthracite. On the basis of calorific value, about 55 percent of the total reserve is east of the Mississippi River, all of which, except for Illinois, is within the three regions covered by this section of the National Power Survey.

a. *Appalachian coals*

The coals of this region contain the largest reserve of high-quality, high-rank, coals in the United States. The estimated total remaining reserve in the region is 271,000 million tons, approximately one-sixth of the total coal of all ranks in the country, on a tonnage basis, of which 95 percent is bituminous coal and the remainder Pennsylvania anthracite. The Appalachian bituminous coal reserve of 259,000 million tons (129,500 million tons at 50 percent recovery) is 36 percent of total bituminous coal, of which approximately 84 percent is high-volatile, 9 percent medium-volatile, and 7 percent low-volatile. These coals generally have low moisture, and high calorific values that range between 12,500 and 14,500 Btu per pound.

The total bituminous reserves of the Appalachian region are distributed among States as follows: West Virginia, 40 percent (104,000 million tons); Pennsylvania, 23 percent (60,000 million tons); Ohio, 16 percent (41,000 million tons); East Kentucky, 11 percent (28,000 million tons); and other States, 10 percent (26,000 million tons). Most of the Ohio reserves are high-volatile bituminous coal. West Virginia, Pennsylvania, and Virginia have high, medium, and low volatile coals.

b. *Midwest*

Indiana and West Kentucky, which also are in the three regions covered by this section of the Survey, have approximately 72,000 million tons of bituminous coal reserves.

2. Special Grade Coals

a. *Metallurgical (coking) coals*

The Appalachian region is the Nation's storehouse of high-grade coking coals. Notwithstanding heavy demands on these coals for the coke ovens of the U.S. steel industry (to which many of them are committed for the future through captive ownership), for export, and for low-sulfur coals to meet air pollution standards, the coking coal reserves of this region are more than adequate to meet all foreseeable demands of the metallurgical coke industry. It has been estimated that the region contains approximately 55,000 million tons of "measured" and "indicated" reserves of metallurgical coal of over 28 inches in thickness which contain no more than 8 percent ash and 1.25 percent sulfur. This can be considered a minimum reserve using generally accepted standards for coking coal. Generally these coals also are excellent for electric utility plants where air pollution is a problem, although their costs are appreciably higher than lower-grade coals conventionally used for steam-power generation. The measured and indicated reserves of these coals are expected to increase further as exploration transfers additional "inferred" reserves to these categories.

b. *Low-sulfur coals*

As air pollution becomes a matter of increasing concern throughout the nation, the availability and cost of low-sulfur coals are of prime importance to the coal and electric utility industries, and also to the general public. Increased costs inevitably will follow where substitutions of higher-grade fuels, available from more distant sources of supply, and therefore at higher transportation costs, become necessary. The problem can be significantly relieved, however, with the early development of commercial processes for the reduction of sulfur in coal and the

reduction or removal of sulfur oxides from stack gases.

Proposed limitations on sulfur levels differ appreciably in various sections of the country. Some are more restrictive than others, depending on many factors, including the degree of consideration given to coal availability and economic costs as measured against atmospheric conditions. Accordingly, there will be differences in availabilities and costs among the respective jurisdictions, related more or less directly to the levels of sulfur established. Table 6 lists Bureau of Mines preliminary estimates of remaining coal reserves, as of January 1, 1965, in the three regions covered by this report—by rank, sulfur content, and state. The data in this table will be revised from time to time as more up-to-date information becomes available, including the results of special surveys now under way by the Bureau of Mines to pinpoint more specifically the extent of reserves, by levels of sulfur content, in the Appalachian area. Concurrently, a survey is being made of current and anticipated mine productive capacity in the same area, and of reserves already committed ("captive" reserves of coking coal; long-term commitments of "commercial" reserves for coking and other purposes; etc.).

Most of the high-rank low-sulfur coals of the Nation are within the regions covered by this report.

Total reserves of coals in the Appalachian region of 1 percent or less sulfur content are estimated at 94,000 million tons (82,000 million tons bituminous; 12,000 million tons anthracite). Of these reserves, 58 percent are in West Virginia, 27 percent in eastern Kentucky, 10 percent in Virginia, 1 percent in Pennsylvania, and 4 percent scattered among other Appalachian states. While these coals generally are considered to be coking coals, some contain excessive ash for coking purposes. In addition, there are some deposits of low-sulfur bituminous coal in Indiana, although the bulk of Indiana coal has higher sulfur levels.

West Virginia has the largest single share of low-sulfur bituminous coals in the Appalachian region, and approximately 63 percent of current production contains no more than 1 percent sulfur; 31 percent ranges between 1.1 and 3 percent sulfur; and 6 percent contains 3.1 percent or more sulfur.[1]

[1] Average sulfur content of coal used by all electric utilities in 1964 was 2.3%. (Bureau of Mines Information Circular No. 8312.)

3. Impact of Quality Substitution

Sulfur limitations of some of the proposed or established air pollution laws and regulations will require increasingly large scale substitutions of lower sulfur coals for the higher sulfur coals used heretofore. In addition to problems of availability resulting from shifts in sources of supply and changes in burning facilities, substitutions generally will mean increased costs of coal. Lower sulfur coals are in higher-cost mining areas than the coals conventionally used for power generation. The latter includes large quantities of strip-mined coals. Also, for the most part, lower sulfur coals originate in mining areas at greater distances from points of utilization than previous sources of supply, which correspondingly increases transportation costs.

C. Productive Capacity of the Coal Industry

In addition to reserves, another important factor with respect to future coal availabilities is the extent to which new productive capacity is added in the coal industry. In this respect, there were announcements during 1967 of planned new annual capacity developed or to be developed during 1967–1970 in the bituminous coal and lignite industry of 63 million tons. Of this quantity 57 million tons are to be in the regions covered by this report. This is supplementary to the substantial new annual capacity developed or announced prior to January 1, 1967. Also, as indicated above, concurrently with new studies of low-sulfur coal reserves, the Bureau of Mines is making a study of the industry's ability to increase capacity in those mining areas which produce low-sulfur coals.

1. Production and Consumption

National production of bituminous coal and lignite has increased steadily since 1961 (403 million tons) to an estimated 551 million tons in 1967, the highest since 1958. Approximately 83 percent of total output is produced in the three eastern regions covered by this report, the great preponderance of which is in the Appalachian area; the balance is in Indiana and West Kentucky.

Table 7 shows shipments of bituminous coal and lignite in 1964 to electric utility plants in the regions covered by this report, by districts of origin and by sulfur content.

Bituminous coal and lignite shipments to electric utilities currently account for 57 percent of U.S.

consumption. Shipments from mines to electric utilities in the three regions covered by this report (226 million tons in 1967) by districts of origin and states of destination, are shown in Table 8. Shipments by districts of origin and methods of shipment are shown in Table 9. Coal originating districts are described in the Appendix.

2. Delivered Price Factors

Prices at which coal is and will be available in different areas vary with differences in mining methods and costs, quality, distances from point of extraction to points of utilization, and many other factors. Among the principal components of delivered coal prices are (1) the f.o.b. mine prices of coal and (2) transportation costs. The following table indicates the relationship between these two factors and trends for the period 1961–1966 for bituminous coal and lignite for the United States as a whole and in the three regions covered by this report (referred to below as "Eastern").

Year	Total production (million tons)		Average value f.o.b. mine		Average rail freight rate		Average mine value plus average rail rate	
	U.S.	Eastern	U.S.	Eastern [1]	U.S.	Eastern [2]	U.S.	Eastern
1961	403	336	$4.58	$4.64	$3.40	$3.45	$7.98	$8.09
1962	422	352	4.48	4.56	3.32	3.39	7.80	7.95
1963	459	383	4.39	4.46	3.21	3.28	7.60	7.74
1964	487	406	4.45	4.52	3.11	3.16	7.56	7.68
1965	512	426	4.44	4.54	3.13	3.17	7.57	7.71
1966	534	442	4.54	4.65	3.01	[3] 3.05	7.55	7.70

[1] Excludes Illinois.
[2] Includes Illinois.
[3] Preliminary.

As indicated in Table 9, in the three regions covered by this report all-rail shipments predominate as the method of transportation. Movements via tidewater, river and ex-river, Great Lakes, truck, and tramway vary in importance in accordance with differences in coal originating areas and in areas of destination (see section on Transportation). Table 10 shows costs of coal consumed in 1966 at electric utilities in the States that comprise the three regions covered by this report. While not strictly comparable with Tables 8 and 9, which show coal shipments from mines to electric utilities, the latter show origin districts, which are somewhat indicative of transportation distances and coal qualities. The differences between "shipments to" electric utilities shown in these tables and "consumption at" these plants, shown in Table 10, represent coal in transit, changes in stocks, and other balancing factors.

In order to minimize any cost increases, and to meet the competition of other energy sources, the coal industry, in cooperation with the mining machinery industry, will continue its extensive program of mechanization, including underground mechanical loading and advanced surface mining equipment, and in cooperation with the transportation industries will work towards reducing the delivered costs of coal. The accomplishments of the coal industry in this respect are indicated by the fact that mechanical loading of underground production has increased from 73 to 92 percent nationally since 1951, and strip mining from 22 to 34 percent of total output. Productivity increased from 7 to 18.52 tons per man day, and there has been significant stability in average f.o.b. mine costs, with some declines, notwithstanding increases in many of the components of coal costs during this period. Based on past experiences, and on expectations for continuing increases in efficiency, the Bureau of Mines has estimated that productivity by 1990 will increase approximately 50 percent with the result that coal costs for power generation in the United States will remain competitive with other energy sources.

D. Mine-Mouth Power Plants

The location of power generating facilities in coal producing areas, at or near the mines, has been practiced for many years on a more or less localized basis. With important technological advancements in EHV transmission which permit the distribution of power over increasingly greater distances, and

the further development of intertie, or grid systems, the potentials for increased growth of the mine-mouth concept have been broadened significantly. Table 13 shows new "mine-mouth' plants in the three regions covered by this report.

"Mine-mouth" plants have many advantages to both the coal and electric power industries. Among these are lessening of air pollution problems, particularly in those metropolitan areas in which generating facilities to meet increasing consumer demand would otherwise be located. They reduce the need for and the cost of transporting and handling coal in bulk form, as well as problems of storage and ash disposal in metropolitan areas. They give coal an increased and "captive" market which otherwise might be served by competing energy sources. They also make coal-generated power available for the encouragement of economic enterprises over wider distances, from the local producing areas all along the line to distant consuming markets.

E. Transportation of Coal

1. By Rail

Coal continues to be the largest single item of all railroad traffic. Coal shipments originated by Class I railroads[1] in 1966 represented one-fourth of their total freight tonnage of 1.4 billion tons and produced one-eighth of all freight revenues.[2]

In the case of Eastern District railroads, which serve the major coal fields east of the Mississippi River, coal shipments in 1966 represented 36 percent of total Eastern District tonnage and accounted for 20 percent of their freight revenues.

Rail transport accounted for three-fourths of all coal tonnage loaded at the mines in each of the years 1963–1966. The balance was more or less equally divided between shipments by water and truck, as shown by the tabulation below. These data relate to bituminous coal and exclude the relatively small amounts (about 3%) of anthracite coal and lignite mined in those years.

a. *Railroad revenues from coal*

Gross revenue of Class I railroads from originated tonnage of bituminous coal has increased from the low point in 1961. On the other hand, average gross revenue per ton of bituminous coal hauled

[1] Railroads having gross annual operating revenues of $5,000,000 or more, according to ICC classification.

[2] ICC: Freight Commodity Statistics.

Coal Movement in Millions of Net Tons [3]

	Loaded at mine for shipment by		Shipped by motor vehicle	Used at mine	Total production
	Rail	Water			
1963.....	334	51	61	13	459
1964.....	349	59	66	13	487
1965.....	372	60	68	12	512
1966 [4]....	387	62	67	18	534

[3] NCA: Bituminous Coal Facts, 1966; US Bur. of Mines, 1965–66 data.

[4] Table No. 9.

by Class I railroads has trended downward during this same period, as indicated in the tabulation below.

Gross Revenue of Class I Railroads from Bituminous Coal [5]

	Total ($ million)	Average ($ per ton)
1961........................	1, 009	3. 40
1962........................	1, 035	3. 32
1963........................	1, 065	3. 21
1964........................	1, 057	3. 11
1965........................	1, 096	3. 13
1966........................	1, 106	3. 01

[5] ICC freight commodity statistics.

b. *Volume train movement of coal*

The decline in average railroad gross revenue per ton of bituminous coal, as shown in the preceding tabulation, reflects among other things reductions in freight rates, averaging 30–50 percent on some deliveries, made possible by volume train movements of coal introduced by the railroads to meet the competition of other fuels and other means of transporting energy.

The railroads have developed the unit train to implement the new concept of economical operation by volume train movements of coal. The unit train consists of light large capacity cars carrying up to 12,000 tons or more of coal on regular schedules between a single mine or group of mines and a single destination. Cars and related facilities provide for fast loading and unloading, which permits greater utilization of capital investment, with resulting operating economies.

The unit train is helping coal to maintain its position in the highly competitive fuels market. A major coal company reported that 80 percent of the coal it shipped to electric utilities in 1965 moved by unit train.[6] Industry-wide, it is estimated that one-third of all coal moved from mine to market in unit trains in 1967.

An increasing number of coal companies and utilities are investing in coal cars of their own to obtain the benefits of even greater rate reductions with unit train service. A leading coal producer expects that by 1969 about 800 large capacity coal cars of its own will be moving several million tons of coal annually to its electric utility customers in unit trains.[7]

Fast loading and unloading of coal is an essential element contributing to unit train economies. Developments in this area include specially designed 100-ton hopper cars of a major coal carrier which can unload 7,200 tons of coal in 20 minutes at a cost of around one cent per ton compared with its usual experience of 4.5 cents. The cars are designed for automatic unloading while in motion through electronic activation of the dumping equipment on the cars.[8]

While unit trains provide train load movements to many of the major electric generating plants at substantially reduced rates, the shuttle train offers some of the more imaginative innovations in energy transportation that will contribute to lower fuel costs. The shuttle train is designed and operated solely to provide fast express service between a single coal mine and plant and usually includes such features as large capacity cars with locomotives distributed throughout the train, loading and unloading in motion, and elimination of classification yards and layover points.

A coal industry study shows that between 1965 and 1970, a total of 22 new generating units of 10,675 megawatts capacity in 13 electric generating plants will rely mainly on shuttle trains for fuel transport. The utility or coal operator will own the cars of the shuttle trains in a majority of the cases.[9]

Even so, the unit train and the shuttle train may represent only steps in the direction of the more advanced "integral" train with is greater capacity cars, numerous engines spaced throughout the train, and other special equipment involving large new capital expenditures to provide a high-speed shuttle service between mine and market. Successful application of the integral train concept will depend in part on the ability of shippers and receivers to handle the large volumes necessary for economical operation.[10]

Expansion under the integral train concept is limited by the number of electric utility plants that can meet the minimum loading requirements of 1.5 million tons of coal per year. This analysis of the situation was made several years ago by a leading railroad car manufacturer, who estimated at that time that only 10% of electric plants consuming 45% of utility coal could meet such minimum requirements.[11]

A more recent estimate for purposes of this survey indicates no significant change in the foregoing analysis. The results of this study covering the United States and the three regions covered by this section of the survey (referred to below as Eastern), are as follows: [12]

	All plants		Plants consuming over 1.5 million tons of coal			
	Number	Million tons per year	Number	Percent	Million tons per year	Percent
United States	548	264.3	48	8.8	105.5	39.9
Eastern	423	205.8	37	8.7	83.0	40.3

c. *Unit Train Rates*

The coal industry considers unit train rates in the 4 to 6 mils per ton mile range an absolute necessity to successfully compete with other fossil fuels and the atom.[13]

This objective is still far from realization. A recent coal industry compilation of trainload rates for

National Coal Association: Ibid, p. 32.

[7] Railway Age, November 21, 1966.

[8] Railway Age, February 20, 1967.

[9] Electrical World, November 15, 1965.

[10] I. H. Benham (R. W. Pressprick & Co.), October 1964: Can Railroads and Coal Industry meet challenge of lower Atomic Power Costs?

[11] I. H. Benham, ibid.

[12] NCA: Steam Electric Plant Factors, 1966.

[13] Railway Age, February 21, 1966.

unit train shipments of bituminous coal from Pennsylvania and West Virginia mines to eastern destinations indicates a weighted average rate of 7.85 mils per ton-mile for an average haul of 414 miles. A similar compilation of train load rates applicable to bituminous coal shipments to New England destinations averaged 7.07 mils per ton-mile for an average distance of 605 miles.[14]

Trainload rates have since been increased, in some cases by ten percent or more. Effective February 4, 1967, these rates on bituminous coal were increased by 10 cents per ton to New England destinations and 35 cents per ton to all other points. The increases were said to be due to inflationary cost increases and railroad industry re-evaluation of the economics of unit train operations.

Subsequently, in March 1968, the railroad industry petitioned the regulatory agency for an increase in rates and charges on all commodities (Ex Parte 259), amounting to 5 percent with a maximum of 15 cents per ton of coal.[15]

In short, greater economies must be achieved in coal transportation through technological advancement and improved operating techniques if the projected goal of 4 mils per ton-mile by the 1980's is to be realized.

2. Movement of Coal by Pipeline

a. *The Cleveland Electric Illuminating coal slurry pipeline*

The feasibility of moving coal in slurry form by pipeline has been demonstrated by successful operation of the 108-mile pipeline which served the Cleveland Electric Illuminating Company from Cadiz, Ohio to its Eastlake plant between 1957 and 1963. The pipeline operation was discontinued when lower trainload rates for bituminous coal to all C E I plants, induced in part by the pipeline, rendered it economically unattractive.

b. *Proposed Southern California Edison pipeline*

Now on the drawing boards is a 275-mile pipeline which will carry Arizona coal in slurry form to the proposed 1,510 megawatt plant of Southern California Edison and other participating utilities in southeast Nevada.[16] The bulk of the electric power will be delivered over long distance transmission lines to southern California. The project is a major facility of Western Energy Supply and Transmission Associates, a planning group consisting of 22 member utilities in seven western states.

The contract with a leading coal producer calls for no less than 117 million tons of coal for the proposed pipeline to be delivered over a 35-year period. It is considered the "largest single coal agreement in the history of the coal industry." The pipeline is a subsidiary of Southern Pacific R.R.

The coal slurry will be a 50–50 (by weight) mixture of coal and water which subsequently will be de-watered to 25 percent water content before being fed into pulverizers for final drying and grinding. The resultant clear water will be used for plant make-up, while waste water will be disposed of in an evaporation pond as a pollution prevention measure.

Pipeline transportation of coal must be given careful consideration in the future design of new electric generating plants, in view of its demonstrated capability.

3. Coal-By-Wire

Mine-site plants utilizing extra high voltage (EHV) transmission to carry power to load centers are obtaining increasing acceptance as a result of improved technology of electric transmission and the drive for cleaner urban air, among other things.

A coal industry survey of energy transport plans for new coal-fired electric generating units coming on-line between 1965 and 1971 showed 25 units totaling 14,520 megawatts are at mine-site. These represented 40 percent of all units included in the survey; the method of fuel supply of the balance of new units surveyed is chiefly by shuttle train and waterways.[17]

Mine-mouth location with its decreased generation costs may offset costs of transmission to the load center, so as to achieve an economic balance. Transmission technology is advancing to the point where 500 kv transmission voltage is a commonplace and higher voltages in the 700–800 kv range, capable of transmitting 4,000 megawatts of power in a single overhead circuit, may be feasible by 1990.

The economics of extra high voltage transmission is grounded on the principle that the power loading of a transmission line is proportional to the square

[14] Bituminous Coal Producers Association: Tabulation from FPC Staff.

[15] To become effective May 27, 1968 if approved.

[16] Electrical World, January 23, 1967; Oil & Gas Journal, January 16, 1967.

[17] Electrical World, November 15, 1965.

of the voltage, whereas line costs and related terminal costs increase only as the first power of the voltage. As a result, unit capital expenditures and unit transmission costs decrease with increases in voltage.[18]

The increasing public concern over aesthetics has intensified research into the economic feasibility of undergrounding transmission lines in more developed areas as well as providing stimulus for new design of transmission towers to improve their appearance.

4. Water Transportation of Coal

One-third of all shipments of bituminous coal to destinations in the United States, Canada and Mexico (excluding overseas exports and minor uses) are water-borne via rivers and tributaries, the Great Lakes, and tidewater during all or part of their journey. Coal loaded at the mine for shipment by water represents one-eighth of all coal production.[19]

Barge lines are adopting some of the cost-cutting techniques of train-load and shuttle train movements, resulting in a major extension of barge operations on inland waterways and at tidewater.[20]

A study by a coal industry consultant indicates that 13 new electric generating units scheduled for operation beween 1965 and 1969 aggregating 4,365 megawatts capacity will receive more than 12 million tons of coal annually by waterway routes.

A recent Electrical World survey shows that by 1980 waterways will move or assist in the movement of an additional 24 million tons of coal per year to 23 new electric generating units with total capacity of 9,648 megawatts.[21]

[18] Transactions IEEE, Vol. PAS–85, June 6, 1966.

[19] NCA: Bituminous Coal Facts, 1966; p. 96.

[20] Electrical World, November 15, 1965.

[21] Electrical World, April 3, 1967.

V. NATURAL GAS

A. Introduction and Summary

The continued importance of natural gas to the fuel economy of the electric industry is unquestioned notwithstanding the phenomenal growth of nuclear power projected in the next two decades. The relatively pollution-free quality of natural gas has enhanced its value for producing electric energy, at least for the short term.

Reserves of natural gas in the United States, both proven and potential, are estimated to be on the order of 1,000 trillion cubic feet and should be adequate to meet requirements in the foreseeable future.

Natural gas requirements for all purposes in the United States during the next two decades are expected to increase at an average annual rate of approximately 3 percent, rising from 17.8 trillion cubic feet in 1966 to 36 trillion in 1990.[1] Gas as fuel for electric generation represented 14.6 percent of total U.S. natural gas requirements in 1966. Natural gas consumed in producing electricity in the three eastern regions covered by this report will increase by about 124% over current consumption levels to 545 billion cubic feet by 1990; however, gas will account for only 2% of total electric generation in 1990 compared to 3.9% today.

Gas-fired total energy systems are gaining increasing acceptance by the commercial and industrial market and will make inroads in the electric utility industry's business.

B. Reserves

Proven recoverable reserves of natural gas in the United States, exclusive of Alaska and Hawaii, approximated 286 trillion cubic feet as of December 31, 1966, according to estimates of the Committee on Natural Gas Reserves of the American Gas Association.[2] This is equivalent to about 12,000 million tons of high grade bituminous coal and is sufficient to last about 16 years based on 1966 net production of 17.5 billion cubic feet.

The additional gas that ultimately may be discovered and produced—the potential gas supply—has been estimated as 690 trillion cubic feet as of the end of 1966. This estimate was made by the industry's Potential Gas Committee under the sponsorship of the Mineral Institute of the Colorado School of Mines, and represents gas supply not proved by drilling and therefore classified as "probable," "possible" or "speculative" depending upon geologic conditions and degree of exploration.[3] The Committee's estimate by supply areas and classifications is as follows (trillion standard cubic feet):

	East	Central	West	Total
Probable	55	220	25	300
Possible		170	40	210
Speculative	60	80	40	180
Total	115	470	105	690

The East supply area in the foregoing tabulation is approximately coterminous with the Northeast, East Central, and Southeast Regions in this report.

C. Annual Requirements

Annual natural gas requirements in the United States, exclusive of Alaska and Hawaii, for the period 1966–1990 have been estimated by the gas industry's Future Requirements Committee under sponsorship of the University of Denver Research Institute.[4] Following are the Committee's estimates of annual requirements for the United States and Regions 1 to 4, which include the Northeast, East

[1] Future Natural Gas Requirements of the United States, Vol. No. 2, June 1967.

[2] Potential Supply of Natural Gas in the United States as of December 31, 1966, Prepared by Potential Gas Committee.

[3] Ibid.

[4] Future Natural Gas Requirements of the United States, Vol. No. 2, June 1967.

Central, and Southeast Regions plus Illinois and Wisconsin (trillion standard cubic feet):

	United States	Regions 1 to 4
1966	17.8	6.5
1970	21.5	7.7
1975	25.5	9.1
1980	28.6	10.4
1985	32.0	11.9
1990	36.0	13.5

The rate of annual increase of future natural gas requirements reflect the degree of maturity achieved by the gas industry following its phenomenal growth during the era of pipeline expansion beginning shortly after World War II. The average annual rate of increase for the period 1966–1990 is expected to be on the order of 3 percent—a substantial slowing down of the earlier growth rates.

	Annual percent of increase	
	United States	Regions 1 to 4
1966–75	4.1	3.8
1975–90	2.3	2.7
1966–90	3.0	3.1

D. Gas for Electric Generation

1. Statistical Data

Natural gas as fuel for electric generation in the United States during the five-year period from 1961 to 1966 increased from 1.8 to 2.6 trillion cubic feet,[5] an average annual growth rate of 7.4 percent for the period. The gas used for electric generation represented 14.6 percent of total natural gas requirements of 17.8 trillion cubic feet in 1966.[6]

In the Northeast, East Central and Southeast Regions, a survey conducted by this Committee indicates that gas for electric generation during the period 1966–1990 will increase from 243 to 545 billion cubic feet, representing an average compounded annual increase of 3.4 percent for the period.

[5] Federal Power Commission: Electric Power Statistics.

[6] Gas consumption in 1966 by electric utilities covered in this report is given in more detail in Table 11.

2. Role in Pipeline Economy

To the extent that natural gas for electric generation is off-peak or "valley" gas, it tends to promote pipeline economy by permitting a higher load factor operation than otherwise would be possible if pipelines loading were determined solely by gas consumers' daily and seasonal requirements. This results in lower rates for gas service to consumers.

3. Regulatory Policy

The Federal Power Commission, which has jurisdiction over gas use through its regulation of interstate pipelines, has in special situations authorized some additional gas for use in electric generation. The Commission's policy in this respect is to determine the public interest in each individual case, balancing long-term conservation against short-term benefits of air pollution control and fuel economics.

4. Gas Prices

The price of gas at the wellhead and to the consumer, including electric utilities, has remained relatively stable since 1960, as shown below.[7]

Average Wellhead and Consumer Price of Natural Gas

Year	Average wellhead (cents/MCF)	Consumer cost by class of service (cents/MCF)		
		Residential	Commercial	Industrial (Including electric utilities)
1960	14.0	97	77	33
1961	15.1	100	78	34
1962	15.5	100	79	35
1963	15.8	100	79	35
1964	15.4	100	78	34
1965	15.6	100	78	35
1966	15.9	100	77	35

E. Gas-Fired Total Energy Systems

Gas-fired total energy (TE) systems which combine on-site electric generation with waste heat utilization for air conditioning and process heat have been achieving increasing acceptance by the commercial and industrial market since the early 1960's. The number of installations was about 100

[7] American Gas Association, Gas Facts, 1966.

in 1964, in excess of 430 in 1967, and is expected to rise to 680 by the end of 1968.[8]

A recent market sutdy conducted for GATE (Group to Advance Total Energy) by Battelle Memorial Institute predicted a potential TE market of 72,000 new and existing commrcial buildings through 1971; approximately one-fourth of these buildings are located in the eastern section of the United States.

F. Liquefied Natural Gas

The shipping and storing of liquefied natural gas (LNG) has only recently advanced from the theoretical to the commercial feasible stage. The first commercial shipment of LNG, from Algeria to the United Kingdom and France, was delivered in 1964. More recent contracts provide for large deliveries of LNG from Alaska to Tokyo, commencing in 1969.[9]

In the United States, several gas transmission companies are studying the economic feasibility of importing substantial volumes of LNG from Venezuela to provide new sources of gas to supplement their domestic supplies. The objective is to deliver pipeline quality gas in New York at competitive rates.[10]

G. Coal Gasification

Technology for producing low-Btu synthetic gas from coal has long been available. The major emphasis in the development of coal gasification processes today is on the production of high-Btu gas with a minimum heating value of 950 Btu per cubic foot.

[8] Electric Light and Power, February 1968.

[9] Business Week, February 19, 1966; Oil & Gas Journal, January 1, 1968.

[10] Oil and Gas Journal, November 20, 1967.

A product of this quality could be blended with natural gas without seriously diminishing unit heating value, and could be transported economically through new or existing pipline systems from points of manufacture to centers of consumption.

For different reasons, government, coal interests, and elements of the natural gas industry have joined to support research and development in coal gasification: government—to broaden the energy resource base; the coal interests—to develop new markets for coal; and the natural gas industry—to insure a long range supply of economical gaseous fuel. There has been a significant increase during the past 5 years in efforts directed toward coal gasification.

There are several reasons why coal is receiving favorable consideration:

1. Coal is an abundant indigenous resource.
2. Coal prices tend to remain relatively stable.
3. Coal is a relatively inexpensive feedstock for gasification processes. In most areas of the country coal or lignite is available at 10 to 20 cents per million Btu at the mine, whereas the price of the lowest grade petroleum product that might be used as feedstock for gasification is 40 to 50 cents per million Btu.

At present, the cost of manufacturing gas can only be estimated. With coal at 15 to 16 cents per million Btu the cost of producing gas by any one of the proposed gasification processes would be about 50 cents per million Btu. Depending on the size of the plant, the price of coal, credits for byproducts (sulfur), assumed rate of depreciation, and anticipated average return on equity capital, synthetic pipe-line quality gas might be as low as 40 cents per million Btu. At present, the average price of natural gas available for resale near centers of consumption is 35 cents per million Btu.

VI RESIDUAL OIL

A. Introduction and Summary

The outlook for residual oil for electric generation has been somewhat dimmed by two major developments since the National Power Survey was originally issued in 1964. First, the sudden emergence of environmental quality as a major public concern and the resulting emphasis on low-sulfur fuel. Second, the widespread acceptance of nuclear power with its economic incentive and its appeal as a pollutant-free source of energy, notwithstanding certain urban-siting problems still to be resolved. The impacts of these and other developments are reviewed in this study.

Residual oil will have a diminishing role in electric generation during the next two decades, both in absolute values and percentagewise. Government oil import regulations, fuel desulfurization and stack emission control and costs, and developments with respect to a synthetic crude oil industry based on coal and oil shale are major factors affecting the future role of residual oil in the interfuel competition for electric generation.

B. Availability of Residual Oil

1. Production and Imports

Domestic residual fuel oil production dropped 21 percent between 1960 and 1966 despite increased refinery crude runs, as refineries converted their residuum to more economically attractive products. Asphalt production increased almost twice as fast as crude runs, while coke production grew almost three times as fast. The following table shows how the disposition of residuum has changed since 1960:[1]

	Thousand barrels daily		
	1960	1966	% change
Domestic residual fuel oil production	910	723	(−21)
Residual fuel oil imports	630	1, 032	64
Total residual fuel oil	1, 540	1, 755	14
Asphalt production	270	355	31
Coke production	71	105	48
Refinery crude runs	8, 088	9, 444	17

The relatively low yield of residual oil from the domestic crude makes the domestic supply of residual fall far short of requirements. As a result, the federal oil import policy, which will be discussed later, is a critical factor. Imports represented 42 percent of total residual oil availability in 1960 and 59 percent in 1966.

2. Consumption

Total consumption of residual fuel oil for all purposes in 1966 according to the Department of Interior unpublished report of August 1967, is shown below:

End use	Total United States		Eastern coastal areas	
	Million barrels	Percent of total	Million barrels	Percent of total
Heating	167	27	138	33
Industrial	141	23	95	23
Electric utility	141	23	112	27
Vessels	74	12	34	8
Military	42	7	20	5
Other	49	8	18	4
Total	614	100	417	100

Electric utilities reporting to the Federal Power Commission [2] increased their use of residual oil for electric generation from 86 to 141 million barrels between 1961 and 1966. The annual rate of increase was much greater in the later years but averaged 10 percent for the period.[3] Most residual oil is used in the coastal states where large tanker deliveries from Venezuela and, more recently, from Africa, minimize transportation costs.

Electric utilities in the Northeast, East Central and Southeast Regions included in the recent survey conducted for this report estimate that residual oil

[1] Department of Interior unpublished study, August 14, 1967.

[2] Oil used in 1966 by electric utilities covered by this report is shown in more detail in Table 12.

[3] Federal Power Commission: Electric Power Statistics.

alone of all fossil fuels for electric generation will decrease both in absolute values and percentage-wise during the next two decades. Oil use will decrease from 105 million barrels in 1966 to approximately 57 million barrels in 1990. Oil's share of the electric generation fuel mix will drop from ten percent to one percent during the period.

C. Current Sulfur Content of Residual Fuel Oil

An American Petroleum Institute (API) survey covering 96 percent of domestic refining capacity shows the average sulfur content of domestically produced No. 6 residual oil to be 1.6 percent by weight. This closely checks with the 1966 Bureau of Mines survey which showed a 1.7 percent average sulfur content. About one-third of the samples analyzed in the Bureau of Mines survey showed a sulfur content of 1 percent or less.

Over 85 percent of the residual fuel oil which is imported into the United States originates in seven large refineries located in Venezuela, Netherlands Antilles and Trinidad. Venezuela is the principal source of crude for these refineries. The typical residual fuel oil imported from these Caribbean sources contains 2.5 percent sulfur.

The African crudes (Lybian, Algerian, and Nigerian) generally are low in sulfur content and will produce residual fuel oil with 1.0 to 0.5 percent sulfur without desulfurization. The fuel oil, however, is usually substantially lower in viscosity and higher in pour point than the residual fuel oil now consumed in the United States. This presents some problems in converting U.S. consumers to African fuel oils.

D. Cost of Residual Fuel Oil Desulfurization

To lower the sulfur content of the fuel oil, it is necessary to lower its gravity and viscosity. The heat content of the fuel oil decreases directly with sulfur reduction, thus necessitating an adjustment in the overall economic cost. A comprehensive engineering study recently was completed for API showing the cost of desulfurizing Venezuelan residual fuel oil in a large scale operation. The following costs were calculated: [4]

[4] Memorandum from Director of Office of Oil and Gas to Assistant Secretary Mineral Resources, August 14, 1967.

Fuel oil sulfur content (weight percent after desulfurization)	Incremental cost per barrel based on 5-year payout	
	Volume basis	Heat equivalent basis
2. 5 (feed stock)		
1. 5	$0. 40	$0. 50
1. 0	. 58	. 72
0. 5	. 80	. 97

These costs are for a Venezuelan operation. Costs to do the same job in the United States would be somewhat higher due to higher fuel and hydrogen cost. Presumably, high sulfur residuum could be used as fuel in the Caribbean. These costs include a credit for the recovered sulfur of $32 a long ton.

E. Federal Oil Import Policy

Restrictions on oil imports were imposed by the President under the Trade Agreements Act of 1955 as extended in the Trade Expansion Act, which authorizes him to impose quantitative restraints on imports if they threaten to impair national security. The Oil Import Administration, under the supervision of the Assistant Secretary-Mineral Resources, discharges the responsibilities imposed upon the Secretary of the Interior by Presidential Proclamation 3279 of March 10, 1959, as amended, "Adjusting Imports of Petroleum and Petroleum Products Into the United States." This proclamation, in the interests of national security, imposes restrictions upon the importation of crude oil, unfinished petroleum oils, and finished petroleum products. The Administration allocates imports of these commodities among qualified applicants and issues import licenses on the basis of such allocations. At the present time, imports of residual fuel oil are licensed but not limited on the Eastern Seaboard.

At the present time, foreign oil can be imported at considerably lower costs than some domestic oil. This availability of foreign oil is in part a consequence of Federal policies. United States oil companies have been energetic in foreign exploration for many years. The Federal Government has encouraged their activities by attempting to maintain and develop mutually beneficial trade and investment relations with oil-producing countries. There are strong advantages—national security and otherwise—to having a viable domestic industry, but im-

portant economic and security benefits stem also from a well-developed foreign supply, particularly one that is well diversified in source and ownership. The other sources of oil in both hemispheres—distributed in many countries and produced by many different companies, most of which have holdings in more than one area—add much to the security of supply for the United States.

F. Oil From Coal and Shale

Potential synthetic crude oils processed from reserves of coal, oil shale and tar sands afford greater national security than the alternative of increasing reliance on oil imports.

Industry sources estimate that 2.5 trillion barrels of synthetic oil could be recovered from United States coal reserves, plus 650,000 million barrels from U.S. oil shale and 300,000 million barrels from Canada's tar sand.[5]

The pilot-plant stage has been reached with coal-derived synthetic oil, although commercial feasibility may still be 10 to 15 years away, depending on future developments in the competitive fuel market. Technology is farther advanced for coal liquefaction than for shale oil extraction as a result of joint industry-government research efforts.

Advantages of coal over oil shale in the production of synthetic oil include greater product yield—about 3 barrels of oil per ton of coal to 0.8 barrel per ton of shale—and practically no waste disposal problem. All coal is either liquefied or converted to char for use as plant fuel—compared to the big problem presented by waste shale. A disadvantage of coal vis-a-vis shale is the cost of the large volumes of hydrogen required in liquefying or gasifying coal. Another plus factor for shale is the recovery of valuable minerals in the shale mining and processing operation.[6]

Development of a U.S. shale oil industry depends upon release by the government of oil shale lands, most of which are said to be in the public domain, to private industry. A test case with respect to the validity of asserted mining claims is pending decision in the courts.

Canada's first tar sands project, which is expected to produce a synthetic crude oil competitive with natural crude, went into operation in 1967.[7]

[5] National Coal Association: Coal News, March 1, 1968.

[6] Oil and Gas Journal, December 18, 1967.

[7] The Commercial and Financial Chronicle: October 26, 1967.

VII NUCLEAR POWER

A. Introduction and Summary

Nuclear power technology progressed steadily from the days of the Shippingport, Dresden, and Yankee prototype generating stations of the late fifties till about the end of 1965. At this point, a combination of competition in the budding nuclear industry, practicable light water reactor systems, and electrical system demands for large, economical units coincided. The result was an unparalleled surge in the industry to "go nuclear." During 1966, nearly one half of the new generating capability ordered was nuclear.[1] This phenomenal growth has been characterized by a broad and intensive industrial participation, with an awareness that the associated manufacturing and uranium industries must develop rapidly to meet the demand. Similarly, the need has become evident for fast breeder reactor development to improve nuclear fuel resources utilization and to better utilize the expected plutonium production of the present generation of light water reactors. Availability and cost of fossil fuels, improved capital investment aspects of larger nuclear systems, and the impact of air pollution on public opinion have been major considerations in fossil versus nuclear decisions. Indications are that nuclear power will assume an ever increasing role in power production, with a gradual transition to the economically advantageous fast breeder systems as that technology develops, predicted for the 1980's.

The great strides made in nuclear technology and the foresight of the Federal Government in encouraging private industry to put the nuclear industry on a free enterprise basis has gone far toward making nuclear power economically competitive. Fast rising future energy requirements place even greater demands on development of nuclear power, and exploitation of all our fuel resources, and thus charges government and industry with having to meet these needs through the use of advanced concepts such as the fast breeder system, and more economical construction and operating techniques.

[1] "The State of the Nation's Power"—C. P. Avila, President EEI, speech to N.Y. Society Security Analysts January 17, 1968.

B. Operating Experience

As of January 1, 1968, there were 16 operable nuclear power stations in the United States totaling 2,810,000 kilowatts of capacity.[2] Units range in size from about 10,000 to 500,000 kilowatts of electrical generating capacity. The 462,000 kw Connecticut Yankee Unit No. 1 (Haddam Neck, Conn.) achieved criticality on July 24, 1967 and reached full power in January, 1968. The 430,000 kilowatt San Onofre Plant of Southern California Edison and San Diego Gas and Electric went into regular commercial operation shortly after its dedication in January, 1968. In 1967 the Peach Bottom (Phil. Elec. Co.) high temperature gas cooled reactor went into commercial operation, demonstrating the practicability of this concept. However, most of the reactor systems in operation are of the light water cooled and moderated variety. Experience from the pioneer 90,000 kilowatt Shippingport Plant (Duquesne Light Co.—1957), the 200,000 kilowatt Dresden Plant unit (Commonwealth Edison Co.—1959), and the 175,000 kilowatt Yankee Rowe Plant (Yankee Atomic Co.—1962) has shown over a period of years the practicality and dependability of light water reactor systems. Consolidated Edison's 265,000 kw Indian Point Unit One (1962) is also building an impressive operating record. Operating, maintenance and availability experience of these units has been such as to convince the electric utility industry that their new generating requirements can be met safely and reliably by nuclear power.

C. Nuclear Power Economics

From its earliest conception, the main interest in nuclear power by the utility industry was in its potential for reducing costs of electric generation. Early nuclear vs. fossil cost studies indicated that

[2] AEC Release January 11, 1968.

while capital investment would be higher for nuclear plants, the fuel portion of generating costs would be much lower. The challenge therefore was to reduce total costs of nuclear generation and particularly investment costs, to compete with fossil generation. Between 1964 and 1967, dramatic reductions in the capital costs of nuclear power systems took place for the following basic reasons:

Increased Unit Size—"Economy of scale", or the lower unit cost which results with larger units and larger components. The reactor and steam generator vessels, handling equipment, instrumentation and buildings represent a high portion of investment cost for any installation. Substantially less dollars per kilowatt of capacity are required by the large size units (500 mw–1,200 mw) present building and planned.

Experience.—Experience by both reactor manufacturers and the utility industry has resulted in lower capital costs due to a more well developed technology.

Competition.—Increased competition in the manufacturing industry for utility contracts has resulted, and should continue to result, in lower construction and nuclear fuel costs, as well as design improvements for increased reactor system efficiency.

It should be noted that by mid-1967 prices of nuclear steam supply systems rose substantially above those offered in 1966.[3] This component cost increase apparently has not yet been a deterrent to the competitive position of nuclear plants, based on the continued announcements of new nuclear units.

The table below summarizes current estimates of the relative investment costs for comparable size, two-unit fossil and nuclear stations in the areas covered by this report. Cost estimates are based on actual cost data reported for construction of existing plants and available estimates on construction now underway for 1968–1974 completion.

[3] Nuclear Industry, July 1967.

Estimated Investment Costs of Two-Unit Base Load Steam-Electric Plants Fossil-Fueled and Nuclear (Exclusive of Step-Up Substations) January 1, 1968 [4]

Power supply area	Unit size (MW)	Plant capacity (MW)	Type of construction	Fuel	Total cost (million dollars)	Cost per kilowatt
Northeast:						
1 and 2	750	1,500	Conventional	Nuclear	$240.0	$160
	600	1,200	Conventional	Coal/Oil	168.0	140
3 and 4	1,000	2,000	Conventional	Nuclear	310.0	155
	1,000	2,000	Conventional	Coal/Oil	280.0	140
5 and 6	1,000	2,000	Conventional	Nuclear	300.0	150
	800	1,600	Outdoor Blrs	Coal	200.0	125
East Central:						
7	500	1,000	Outdoor Blrs	Coal	130.0	130
8, 9, 10	750	1,500	Conventional	Nuclear	225.0	150
12 and 19	800	1,600	Outdoor Blrs	Coal	200.0	125
11	750	1,500	Conventional	Nuclear	225.0	150
	750	1,500	Conventional	Coal	187.5	125
Scutheast:						
18 and 21	1,000	2,000	Conventional	Nuclear	280.0	140
	650	1,300	Conventional	Coal	156.0	120
20	1,000	2,000	Conventional	Nuclear	280.0	140
	1,000	2,000	Conventional	Coal	240.0	120
22 and 23	500	1,000	Conventional	Coal	110.0	110
24	750	1,500	Conventional	Nuclear	225.0	150
	500	1,000	Full Outdoor	Coal	125.0	125
	500	1,000	Full Outdoor	Oil	105.0	105

[4] Extracted from "Hydroelectric Power Evaluation," Federal Power Commission, 1968.

NOTE.—The unit cost runs from \$20 to \$25 per kilowatt higher for nuclear units than for coal units—or about 15 to 20% greater.

The ever increasing pressure on industry to abate air pollution is most significant in areas where present and future electrical power needs are the greatest. The certainty of more restrictive air pollution regulations and the economic impact of such regulations is making nuclear power increasingly attractive to the utility industry.

Unlike fossil plants which must have a continuous supply of fuel moving to the site, nuclear plants' relatively small fuel movements are infrequent, and fuel transportation becomes an extremely minor part of production costs. This freedom to locate nuclear plants without geographical regard to fuel sources enhances the installation of nuclear power generating facilities in areas of high fossil fuel costs.

D. Nuclear Fuels

A milestone with significant beneficial effect on the electric power industry occurred with the passage of the Private Ownership of Special Nuclear Materials Act of 1964. This permits the orderly transfer from Government to private ownership of enriched uranium and plutonium produced by irradiation. The following table shows the timing of the related changes.[5]

TIME-TABLE

Private ownership permitted______	August 26, 1964.
Toll enriching of privately owned uranium can begin.	January 1, 1969.
AEC prohibited from entering into new lease agreements for power reactor fuel.	January 1, 1971.
AEC guaranteed purchase price for plutonium will terminate.	December 31, 1970.
Private ownership of special nuclear material mandatory, all prior lease arrangements must terminate.	July 1, 1973.

This legislation already has generated, and will continue to generate, desirable competition in the nuclear fuel industry. The only component of the fuel cycle still in government hands is the enrichment process; and the Atomic Industrial Forum with the AEC has initiated a study of the feasibility and desirability of transferring to private industry one or more of its gaseous diffusion plants for fuel enrichment. The utilities are exhibiting an increased independence from reactor suppliers in making arrangements for reactor fuel loadings beyond those contracted for at the time of placing the nuclear steam supply system orders. The options available to utilities range from that of the reactor manufacturer's full fuel cycle service to that of the utility controlling many of the major steps in the fuel cycle. Recently many of the companies involved in the nuclear fuel cycle industry announced plans for moves into, or expansions, to handle the new requirements. This, combined with the transition by the uranium supply industry from the guarantees of a government supported to a private market, is expected to have a long range favorable effect on nuclear fuel economics.

E. Present and Future Status

The Northeast, East Central and Southeast Regions lead the country in installed, ordered and planned nuclear power generation. In these three regions are located nine of the 16 operable nuclear power plants, 15 of the 21 plants being constructed, and 27 of the 40 plants planned.[6] Most of these future units are in the 800,000 kilowatt range, the largest of which is about 1,100,000 kilowatts capacity.

The survey made by this Committee in 1967 explored the present status and future plans of the utility industry in the Northeast, East Central and Southeast Regions up to 1990. The results are discussed in Section III of this report. This study shows clearly the future plans of the Eastern utilities to utilize an increasingly greater proportion of nuclear-fueled generation; from 0.5% of the total in 1966 up to 65.4% in 1990. The effect of the heavy nuclear plant orders in 1966 and 1967 is clearly shown as the nuclear share of generation moves up to over one quarter in 1975, and in 1980 to nearly one-half of total generating capability in the Eastern United States.

In a recent report of the Joint Committee on Atomic Energy, Mr. Phillip Sporn, retired President and Director, American Electric Power Company, predicts a considerably slower growth for nuclear power than the results of this committee's survey indicated. Due to increased capital costs of nuclear plants starting in late 1967, the lack of units in operation above 500 megawatts size, Mr. Sporn predicts that nuclear power will provide only 34% of the nation's generation by 1987 and 50% by the year 2000.[7] This is markedly less than the percentages predicted by Eastern United States utilities in this committee's survey.

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[5] The Nuclear Industry—AEC, 1967.

[6] AEC Release—January 11, 1968.

[7] "Nuclear Power Economics—1962 through 1967, Report of Joint Committee on Atomic Energy, February, 1968."

VIII EFFECT OF AIR POLLUTION CONTROL ON FUEL AVAILABILITY AND COST

A. Introduction and Summary

Regulations requiring the control of air pollution can become a major factor in the availability and cost of fuels to electric utilities, particularly where fuel characteristics are prescribed. The magnitude, direction, degree and rate of application of such regulations are difficult to predict with any certainty and their effect on availability and price of fossil fuels is, similarly, difficult to determine.

There is no doubt, however, that air pollution controls will be applied to an ever greater degree and over an increasing area. The goal of clean air is prompting action at all levels of government. The most recent laws passed by Congress direct the Federal Government to institute regulations if effective action is not forthcoming from the individual states.

The method of control can have a considerable effect on the fuel supply. If applied through regulations requiring higher quality fuels, a severe dislocation of normal marketing patterns may result. If the emphasis is on control of stack emission rather than fuel characteristics, an alternate choice is available, permitting the fuel consumer to select the most economic method. In this latter case, changes in the fuel market would not be as severe. Other factors are the degree of cleanliness required for the air, and the rate at which regulations are applied in the different areas of the nation.

Increased costs will result to the utility using fossil fuels and to the customers of the utility as a result of air pollution controls. There may be some minor off-setting factors in the form of reduced operating and maintenance costs because of the better quality fuels. In addition, increased electric demand may result as other industrial and commercial organizations, faced with similar regulations, turn toward electricity as their energy source to help solve their own pollution control problems.

Control of sulfur oxide emissions and other pollutants will be required to some degree throughout the nation.

The states that are large producers, as well as consumers, of coal may be reluctant to apply too severe sulfur restrictions to fuels without some indication of the real danger levels. Therefore, the emphasis in some areas may be on the development and installation of suitable stack processes to reduce or remove the pollutants.

A choice of control method, whether stack process or low-sulfur fuel, will give industry greater flexibility in arriving at the most economical solution.

It may be more economical to use lower sulfur fuels than stack processes on smaller and older equipment. Where regulations permit a choice of control method, the higher capital costs of stack systems tends to discourage their use at old plants. The smaller size, poor load factor, and short remaining life, make older plants marginal with respect to utilization of high capital cost equipment. The higher prices of low-sulfur fuels can be accepted more readily.

Conversely, stack systems at new, large fossil-fuel fired plants can prove economical despite the high capital costs. The potential for reduced operating costs over the long remaining life of the plant and at large rates of fuel consumption is the primary reason.

Pollution abatement regulations will result in increased demand for low-sulfur fuels, including conversions from higher sulfur fuels, such as coal and residual oil, to low-sulfur coals, oils and natural gas. Changes in the fuel market may create shortages in supply and higher prices in some areas, while causing disruptions in others.

The net result will be increases in capital and operating expenses for the utilities, which will be reflected in increased rates which will be borne by their customers.

B. Current Aspects of Regulation

The most recent trend, and that receiving the greatest emphasis by government, concerns the control of sulfur oxide emissions from power plant,

industrial and heating unit stacks. Attempts have been made to control this constituent in the Los Angeles area for a number of years by restricting the use of sulfur-bearing fuel oil by the utilities in favor of sulfur-free natural gas. Data concerning the effects of sulfur dioxide are conflicting. Sulfur emission from power plant stacks constitutes only a small fraction of total pollution.

A major attack on the problem is now underway in the metropolitan New York-New Jersey area. Sulfur content in fuel has already been restricted in New York City, New York State and in New Jersey. The U.S. Department of Health, Education and Welfare (HEW) has conducted regional hearings during the year, and a joint compact with the two states is awaiting approval.

The regulations of the three jurisdictions differ in degree and detail but have the same general characteristics:

1. Limitations on sulfur in fuel to 1% or 1½% by weight for existing plants.
2. Further reductions in the limit in the future.
3. Permission to use stack devices to obtain equivalent sulfur reduction.
4. Prohibition against new plants, unless long term supplies of fuel containing less than ¼% sulfur, or equivalent stock control, are provided.

Similarly stringent regulations have been imposed or proposed by other state or local jurisdictions. Examples include Duval County, Fla.; Falls Church, Va.; Montgomery County, Md.; Arlington County, Va.; and Washington, D.C. In some jurisdictions, however, the adoption of stringent regulations has been deferred until stack emission control devices become available.

Less severe limits, equivalent to a range of 1% or 2% sulfur, have been enacted in and around St. Louis, Mo. Progressively more lenient controls are in force or proposed for a number of other scattered local areas or states.

The federal pollution control laws permit local areas to assume the initiative in this matter. Where local initiative is ineffective, HEW may step in and impose its standards for that region. Failure to impose control measures at the local level is, therefore, no guarantee that further action will not be taken.

Although government has played an ever increasing part in the pressure for control, many others are involved in the search for a solution. Research is being sponsored by manufacturers, utilities, and organizations in and out of the utility field to determine factually the actual effects of gases such as sulfur oxides. Results of such scientific investigations will assist greatly in permitting setting of realistic standards. This will allow necessary protection of public health and property and at the same time insure that unduly restrictive and expensive regulations are not imposed.

C. Methods of Sulfur Control

1. Changes in the Art of Generation

The recent upsurge in nuclear plant orders is motivated by both economics and the reduced air pollution potential. Installation of low fuel cost nuclear units will tend to reduce the use of the older fossil units, thereby effecting a further improvement in air quality.

Nuclear stations tend to be base-loaded, necessitating the use of new types of peaking generation. Two of these techniques are pumped-storage and internal combustion units, including gas turbine generators.

Pumped-storage hydraulic systems require energy during off-peak hours to restore the level of water in the upper reservoir. This is done now with efficient fossil equipment which contributes less pollution per unit of energy. As nuclear generation comes on the line, it will provide more and more of these pumping requirements. Internal combustion equipment, such as gas turbines and diesel engines, burn natural gas or low-sulfur distillate fuels.

2. Low-Sulfur Coal

Large quantities of low-sulfur coals are present in southern West Virginia and the contiguous areas of Virginia and Kentucky. Those consumers now using coals mined in Pennsylvania, Ohio, northern West Virginia, and Indiana, could be required to look to the southern fields for large quantities of low-sulfur coal if air pollution regulations are applied on the sulfur content of the coals which they use. In order to meet the demand, production of coal from these low-sulfur areas would have to be increased substantially. The net result would be strong competition for the more suitable coals and an upward surge in prices, while the abandoned coal areas would suffer economic losses in capital, wages, service and taxes.

Not all of the low-sulfur coals are physically or chemically suitable for the boiler-furnaces of the

utilities. Many of the coals tend to be high in ash fusion temperature or more difficult to grind. Much of the utility fuel-burning equipment has been designed for the characteristics typically found in the most accessible fields, including northern West Virginia, Pennsylvania, Ohio and Indiana, and could not be modified for southern coals. In addition, the reserves and output may be dedicated to other consumers, especially to the producers of metallurgical coke for which many of these southern coals are ideally suited.

Another problem stemming from the conversion to low-sulfur coals concerns the effect of reduced sulfur content on electrostatic precipitators. Many of the presently installed precipitators are designed for medium or high-sulfur coals. The use of low-sulfur coals results in a loss of efficiency and a resultant increase in fly ash emitted from the stack. Where this problem is of sufficient magnitude, considerable expense would be involved in supplementing or improving the installed equipment.

Desulfurization of coal is not feasible in the present state of technology to the extent required by most regulations, although there is promise for the future.

3. Low-Sulfur Oil

Those utilities presently burning high-sulfur oil, or considering conversion to oil to solve their sulfur problems, will be faced with an apparently limited supply of naturally-occurring low-sulfur residual products. Such fuel oils generally are made from low-sulfur crudes available in limited areas of the world. The largest share of this crude and resulting residual fuel goes to foreign markets. Although the limited supply prevents any widespread application to the nationwide alleviation of SO_2 pollution, it can be a significant factor in certain localities.

In addition to being in short supply, these natural low-sulfur oils have some characteristics that may present technical problems necessitating substantial capital investments. They have a higher paraffinic content and tend to solidify at temperatures below 100° F. Also, their low viscosity may result in pumping problems.

Desulfurization of the residual oils is technically feasible, because of experience with catalysts and hydro-desulfurization of other petroleum products. Adequate equipment is not installed at present, however, and very sizeable costs and considerable time are required for the installation of such facilities. Some incentive must be supplied to facilitate the authorization of the necessary funds. At present, estimates of desulfurization costs range from 40¢ to $1 per barrel, depending upon the method, feed stock, and final sulfur level.

4. Natural Gas

The use of natural gas is dictated by the economics of competition with other fuels. Where the use of low-sulfur fuels is required by legislation, the price of natural gas becomes less of an obstruction as a result of the greater price of low-sulfur oil or coal.

Sudden and large increases in gas conversions by the utilities or other customers are not immediately possible, however. Increases are limited by pipeline and compressor capacities, which cannot be expanded without substantial investment and considerable time. It is likely that small residential and commercial consumers will receive priority for any increased use, as opposed to electric utilities and other large users, except in certain special cases. The large consumer is better able to install equipment to handle other low-sulfur fuels or to use stack removal devices.

5. Stack Control

Tall stacks are an effective way of dispersing flue gases to prevent excessive ground level concentrations. Even during periods of temperature inversion, the gases may not reach ground level to any appreciable degree. Much effort has been expended here and in Britain to increase the effectiveness of tall stacks, including increased height and other innovations, such as multiple flues.

Tall stacks are generally considered to be an effective interim measure for controlling air pollution. They have not, however, been recognized in most of the recently enacted regulations.

Methods of removal of sulfur oxides from flue gases generally can be classified into two groups—additive systems and extraction systems. Many variations are under study, test, or in the pilot plant stage, but commercial applications are not yet available to any great extent. Some of the processes under study are itemized in the appended list.

The additive systems involve the use of dolomite or limestone, injected into the furnaces directly or with the fuel, or into the "cold" end of the flue gas system. Dry or wet collection systems are required to remove the resultant product and the unused part of the additive, thereby introducing a collateral problem of waste disposal. The wet

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system, with fuel injection of additive, gives promise of a greater sulfur removal efficiency.

The extraction processes are chemical plants which produce a salable product such as elemental sulfur or sulfuric acid. There are many different processes and variations thereof, but they have the same general characteristics, namely: (1) large space requirement—almost equal to that of the power plant itself; (2) substantial capital investment; (3) high operating cost which may be partly offset, depending upon the market for the by-product sulfur or sulfuric acid; and (4) possible operating problems.

The additive systems appear closer to practical application because of their simpler design. Although they require capital expenditures for additive feeding equipment and end-product disposal facilities, these generally are less burdensome than for extraction systems. There are considerable operating costs for the additive and for the collection and disposal of the greater quantity of waste material.

Table 1.—Electric Generation by Type of Fuel and Hydro Power, Northeast, East Central and Southeast Regions, Combined (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Percent Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	491.3	79.5	644.9	77.5	722.9	61.1	740.1	45.2	775.4	35.2	852.3	28.7
Oil	61.6	10.0	58.8	7.1	49.0	4.1	42.6	2.6	39.2	1.8	36.1	1.2
Gas	24.3	3.9	38.9	4.7	39.9	3.4	40.0	2.4	50.2	2.3	57.9	2.0
Nuclear	3.1	.5	42.2	5.1	313.0	26.4	751.9	45.9	1266.0	57.5	1941.7	65.4
Internal combustion	.7	.1	2.0	.2	2.1	.2	2.6	.1	3.4	.1	5.1	.2
Total	581.0	94.0	786.8	94.6	1126.9	95.2	1577.2	96.2	2134.2	96.9	2893.1	97.5
Hydro generation:												
Conventional	36.9	6.0	43.1	5.2	46.4	3.9	46.2	2.8	43.8	2.0	41.2	1.4
Pumped storage	.5		2.0	.2	10.4	.9	15.4	1.0	25.2	1.1	34.0	1.1
Total	37.4	6.0	45.1	5.4	56.8	4.8	61.6	3.8	69.0	3.1	75.2	2.5
Total generation	618.3	100.0	831.9	100.0	1183.7	100.0	1638.8	100.0	2203.2	100.0	2968.3	100.0

Table 2.—Electric Generation by Type of Fuel and Hydro Power, Northeast Region (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Billion	Percent Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	130.5	66.6	157.5	60.0	156.1	41.6	141.9	27.5	122.0	17.9	101.5	11.1
Oil	43.4	22.1	43.8	16.7	36.5	9.7	30.1	5.8	26.0	3.8	23.6	2.6
Gas	9.3	4.7	15.3	5.8	16.9	4.5	15.1	2.9	13.3	2.0	12.1	1.3
Nuclear	2.2	1.1	30.7	11.7	148.5	39.6	309.3	59.8	492.7	72.5	747.1	81.7
Internal combustion	.6	.3	1.3	.5	1.4	.4	2.0	.4	2.4	.3	3.1	.3
Total	186.0	94.8	248.6	94.7	359.4	95.9	498.4	96.4	656.4	96.5	887.4	97.0
Hydro generation:												
Conventional	10.1	5.2	12.0	4.6	12.0	3.2	11.8	2.3	11.4	1.7	11.1	1.2
Pumped storage			1.8	.7	3.5	.9	6.6	1.3	12.1	1.8	16.2	1.8
Total	10.1	5.2	13.8	5.3	15.5	4.1	18.4	3.6	23.5	3.5	27.3	3.0
Total generation	196.1	100.0	262.4	100.0	374.9	100.0	516.8	100.0	679.9	100.0	914.7	100.0

Table 3.—Electric Generation by Type of Fuel and Hydro Power, East Central Region (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	199.7	98.2	269.3	97.1	321.0	85.0	338.8	67.5	371.1	55.8	434.4	49.5
Oil	.2	.1	.3	.1	.1		.1		.2		.2	
Gas	.2	.1	.4	.1	.2		.3	.1	.4	.1	.5	.1
Nuclear	.9	.4	4.3	1.6	50.0	13.2	155.9	31.0	286.1	43.0	433.3	49.4
Internal combustion	.1	.1	.4	.1	.6	.2	.5	.1	.7	.1	1.7	.2
Total	201.1	98.9	274.7	99.0	371.9	98.4	495.6	98.7	658.5	99.0	870.1	99.2
Hydro generation:												
Conventional	1.8	.9	2.4	.9	2.6	.7	2.6	.5	2.7	.4	2.6	.3
Pumped storage	.4	.2	.2	.1	3.3	.9	4.0	.8	4.3	.6	4.0	.5
Total	2.2	1.1	2.6	1.0	5.9	1.6	6.6	1.3	7.0	1.0	6.6	.8
Total generation	203.3	100.0	277.3	100.0	377.8	100.0	502.2	100.0	665.5	100.0	876.7	100.0

Table 4.—Electric Generation by Type of Fuel and Hydro Power, Southeast Region (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent	Billion Kwh	Percent
Thermal generation:												
Coal	161.1	73.6	218.1	74.7	245.8	57.0	259.4	41.8	282.3	32.9	316.4	26.9
Oil	18.0	8.2	14.7	5.0	12.4	2.9	12.4	2.0	13.0	1.5	12.3	1.0
Gas	14.8	6.8	23.2	7.9	22.8	5.3	24.6	4.0	36.5	4.3	45.3	3.9
Nuclear			7.2	2.5	114.5	26.6	286.7	46.3	487.2	56.8	761.3	64.7
Internal combustion			.3	.1	.1		.1		.3		.3	
Total	193.9	88.6	263.5	90.2	395.6	91.8	583.2	94.1	819.3	95.5	1135.6	96.5
Hydro generation:												
Conventional	25.0	11.4	28.7	9.8	31.8	7.4	31.8	5.1	29.7	3.5	27.5	2.3
Pumped storage					3.6	.8	4.8	.8	8.8	1.0	13.8	1.2
Total	25.0	11.4	28.7	9.8	35.4	8.2	36.6	5.9	38.5	4.5	41.3	3.5
Total generation	218.9	100.0	292.2	100.0	431.0	100.0	619.8	100.0	857.8	100.0	1176.9	100.0

Table 5.—Coal, Oil and Gas Fuels for Electric Generation, Northeast, East Central and Southeast Regions (Based on Survey by Fossil Fuel Resources Committee) Years 1966–90

	1966		1970		1975		1980		1985		1990	
	Quantity [1]	Equivalent tons	Quantity [1]	Equivalent tons	Quantity [1]	Equivalent tons	Quantity [1]	Equivalent tons	Quantity [1]	Equivalent tons	Quantity [1]	Equivalent tons
Northeast:												
Coal	57.9	57.9	63.0	63.0	61.8	61.8	56.8	56.8	48.8	48.8	40.6	40.6
Oil	76.5	19.1	69.5	17.4	57.4	14.4	47.8	12.0	41.3	10.3	37.5	9.4
Gas	100.2	4.1	148.5	6.1	162.4	6.7	146.6	6.0	129.1	6.3	117.5	4.8
Total		81.1		86.5		82.9		74.8		64.4		54.8
East Central:												
Coal	82.3	82.3	105.6	105.6	124.5	124.5	131.5	131.5	144.0	144.0	168.5	168.5
Oil	.3	.1	.5	.1	.2		.2		.3	.1	.3	.1
Gas	2.0	.8	3.8	.2	1.8	.1	2.8	.1	3.8	.2	4.8	.2
Total		83.2		105.9		124.6		131.6		144.3		168.8
Southeast:												
Coal	63.2	63.2	84.6	84.6	95.4	95.4	99.6	99.6	108.4	108.4	121.5	121.5
Oil	28.0	7.0	22.6	5.7	19.1	4.8	18.9	4.7	19.8	5.0	18.7	4.6
Gas	140.8	5.8	218.4	9.0	214.8	8.8	229.3	9.4	340.2	14.0	422.2	17.4
Total		76.0		99.3		109.0		113.7		127.4		143.5
Combined total:												
Coal	203.4	203.4	253.2	253.2	281.7	281.7	287.9	287.9	301.2	301.2	330.6	330.6
Oil	104.8	26.2	92.6	23.2	76.7	19.2	66.9	16.7	61.4	15.4	56.5	14.1
Gas	243.0	10.7	370.7	15.3	379.0	15.6	378.7	15.5	473.1	19.5	544.5	22.4
Total		240.3		291.7		316.5		320.1		336.1		367.1

[1] Fuel quantities in millions of tons of coal, barrels of oil and MCF of gas.

NOTE.—Fuel quantities are based on kilowatthour generation by fuels and weighted average heat rates, respectively, reported on the F.F.R.C. questionnaire, and were computed using the following conversion factors: 12,500 Btu per pound of coal; 150,000 Btu per gallon and 42 gallons per barrel of oil; 1,030 Btu per cubic foot of gas. The oil and gas equivalents per ton of coal are 4 barrels of oil and 24.3 MCF of gas, respectively.

Table 6.—Preliminary Estimates of Coal Reserves, Northeast, East Central and Southeast Regions (January 1, 1965)

[Million net tons]

State	Percent sulfur content									
	0.7 or less	0.8–1.0	1.1–1.5	1.6–2.0	2.1–2.5	2.6–3.0	3.1–3.5	3.6–4.0	Over 4.0	Total
Bituminous coal:										
West Virginia	20,761.0	26,710.6	21,819.7	13,290.6	8,496.1	2,491.8	3,147.4	5,949.2		102,666.4
Kentucky:										
East	13,639.9	8,491.9	2,286.8	1,658.8	1,158.3	2,154.4	24.7			29,414.8
West			1,119.6	162.0	336.3	3,793.6	12,759.3	13,643.3	5,081.3	36,895.4
Virginia	1,981.5	6,077.5	1,637.1		123.9					9,820.0
Alabama	889.2	1,189.3	5,421.7	5,182.8	458.8	417.4			18.6	13,577.3
Indiana	197.5	173.0	3,645.2	4,248.8	3,543.4	4,110.5	10,872.8	5,105.9	2,944.0	34,841.1
Pennsylvania	44.0	1,154.4	7,624.4	12,424.9	19,689.5	9,995.6	5,287.6	1,150.5	580.6	57,951.5
Tennessee	3.3	160.9	715.9	258.7	178.2	190.5	219.7	43.8	68.5	1,839.5
Georgia		76.0								76.0
Maryland				124.6	191.8	208.2	378.6	56.4	220.4	1,180.0
Michigan								205.0		205.0
North Carolina						110.0				110.0
Ohio		611.0	369.0	2,110.2	2,750.4	7,810.5	9,785.3	10,148.2	8,439.4	42,024.0
Total bituminous	37,516.4	44,644.6	44,639.4	39,461.4	36,926.7	31,282.5	42,475.4	36,302.3	17,352.8	330,601.5
Anthracite: Pennsylvania	12,211.0									12,211.0
Grand total	49,727.4	44,644.6	44,639.4	39,461.4	36,926.7	31,282.5	42,475.4	36,302.3	17,352.8	342,812.5

Source: Bureau of Mines, Department of the Interior, Information Circular 8312.

Table 7.—Shipments of Bituminous Coal to Electric Utility Plants, Northeast, East Central and Southeast Regions (By Districts of Origin and Sulfur Content) Year 1964

[Thousand net tons]

District	Percent sulfur content			Total
	1.0 or less	1.1–3.0	Over 3.0	
1		22, 527	______	22, 527
2		8, 529	______	8, 529
3 and 6		26, 436	....	26, 436
4		200	22, 843	23, 043
7	1, 005	....	....	1, 005
8	31, 054	13, 350	....	44, 404
9		20, 664	6, 512	27, 176
10		3, 500	1, 787	5, 287
11			8, 774	8, 774
13	575	7, 396	....	7, 971
Total	32, 634	102, 602	39, 916	175, 152
Percent of total	18. 6	58. 6	22. 8	100

Source: Bureau of Mines, Department of the Interior Information Circular 8312.

Table 8.—Shipments of Bituminous Coal to Electric Utility Plants, Northeast, East Central and Southeast Regions (By Districts of Origin and Method of Shipment) Year 1967 [1]

[Thousand net tons]

States of destination	Districts of origin										
	Total	1	2	3 & 6	4	7	8	9	10	11	13
Northeast:											
Massachusetts	3,418	743	2	961		64	1,648				
Connecticut	4,030	2,791		1,091		112	36				
Maine, New Hampshire, Vermont and Rhode Island	719			532			187				
New York	14,330	4,271	163	7,939	239		1,718				
New Jersey	6,402	1,671		4,600			131				
Pennsylvania	23,595	11,306	5,882	6,360			47				
Delaware and Maryland	8,713	5,273	179	3,217			44				
District of Columbia	546	447		4		95					
Total Northeast	61,753	26,502	6,226	24,704	239	271	3,811				
East Central:											
Ohio	30,086	220	575	2,917	21,701	79	2,583	2,011			
Indiana	20,624						650	5,408	3,767	10,799	
Michigan	19,602	192	250	1,107	8,160	19	8,268	838	249	519	
West Virginia	12,671	2,046		5,038	1,011		4,576				
Kentucky	14,087						1,674	10,136	2,277		
Total East Central	97,070	2,458	825	9,062	30,872	98	17,751	18,393	6,293	11,318	
Southeast:											
Tennessee	14,777						7,665	6,375	46		691
Alabama and Mississippi	14,550						108	6,235	21		8,186
Virginia	8,896					811	8,085				
North Carolina	14,349					882	13,467				
South Carolina	3,877					19	3,858				
Georgia and Florida	10,519						5,331	5,059			129
Total Southeast	66,968					1,712	38,514	17,669	67		9,006
Grand total	225,791	28,960	7,051	33,766	31,111	2,081	60,076	36,062	6,360	11,318	9,006

Source: Bureau of Mines, Department of the Interior. (Any differences between "shipments to" and "consumption at" electric utilities represent coal in transit, consumption from stocks, and other balancing factors.)

Table 9.—Shipments of Bituminous Coal to Electric Utility Plants, Northeast, East Central and Southeast Regions (By Districts of Origin and Method of Shipment) Year 1967 [1]

[Thousand net tons]

Methods of shipment	Percent	Districts of origin										
		Total	1	2	3 & 6	4	7	8	9	10	11	13
Northeast:												
All-rail	55	34, 074	15, 700	1, 059	16, 899	239	95	82				
Great Lakes		129			129							
Tidewater	23	14, 483	4, 599	21	6, 000		176	3, 687				
Truck	12	7, 151	5, 176	1, 975								
River and ex-river	7	4, 148		2, 430	1, 676			42				
Tramway, etc.[2]	3	1, 768	1, 027	741								
Total Northeast	100	61, 753	26, 502	6, 226	24, 704	239	271	3, 811				
East Central:												
All-rail	42	40, 943	2, 049	234	276	14, 422	8	6, 178	5, 591	5, 653	6, 532	
River and ex-river	26	24, 867		31	4, 391	3, 522	71	6, 172	7, 818	391	2, 471	
Great Lakes	14	13, 703	192	250	1, 030	5, 831	19	5, 337	276	249	519	
Truck	11	10, 202	217	310	961	3, 132		64	4, 708		810	
Tramway, etc.[2]	7	7, 355			2, 404	3, 965					986	
Total East Central	100	97, 070	2, 458	825	9, 062	30, 872	98	17, 751	18, 393	6, 293	11, 318	
Southeast:												
All-rail	73	49, 227					1, 712	36, 945	7, 160			3, 410
River and ex-river	22	14, 649							10, 509	67		4, 073
Truck	3	1, 990						1, 569				421
Tramway, etc. [2]	2	1, 102										1, 102
Total Southeast	100	66, 968					1, 712	38, 514	17, 669	67		9, 006
Total all regions:												
All-rail	55	124, 244	17, 749	1, 293	17, 175	14, 661	1, 815	43, 205	12, 751	5, 653	6, 532	3, 410
Tidewater	6	14, 483	4, 599	21	6, 000		176	3, 687				
River and ex-river	19	43, 664		2, 461	6, 067	3, 522	71	6, 214	18, 327	458	2, 471	4, 073
Great Lakes	6	13, 832	192	250	1, 159	5, 831	19	5, 337	276	249	519	
Truck	9	19, 343	5, 393	2, 285	961	3, 132		1, 633	4, 708		810	421
Tramway, etc.[2]	5	10, 225	1, 027	741	2, 404	3, 965					986	1, 102
Grand total	100	225, 791	28, 960	7, 051	33, 766	31, 111	2, 081	60, 076	36, 062	6, 360	11, 318	9, 006

[1] Source: Bureau of Mines, Department of the Interior.

[2] Tramway, conveyor, and private railroad.

Table 10.—Coal Consumed by Electric Utilities, Northeast, East Central and Southeast Regions, Year 1966

States	Installed capacity (000 Kw)	Net generation (MM Kwh)	Coal consumed (000 tons)	Cost per ton		Cents per MM btu		Average btu per pound	Percent coal/all fuels (btu basis)
				F.O.B. plant	As burned	F.O.B. plant	As burned		
Northeast:									
Massachusetts	3,793.1	19,717.3	3,725	$8.78	8.98	34.3	35.1	12,788	45
Connecticut	2,235.5	12,363.1	4,429	8.03	8.24	31.2	32.0	12,857	84
Maine	436.6	2,400.8	----	----	----	----	----	----	----
New Hampshire	367.2	1,726.3	311	9.40	9.59	34.6	35.3	13,596	45
Rhode Island	365.1	1,284.0	375	8.96	9.87	32.8	36.1	13,658	62
Vermont	30.0	57.8	32	N.A.	9.89	N.A.	36.1	13,706	100
New Jersey	5,991.4	28,749.8	6,836	7.78	7.97	29.5	30.2	13,184	61
New York State	12,971.5	54,954.0	13,079	7.86	7.97	29.7	30.1	13,223	58
New York City	8,909.3	33,776.1	5,087	8.63	8.64	32.1	32.1	13,459	35
N.Y. Excl. NYC	4,062.2	21,177.9	7,992	7.38	7.54	28.2	28.8	13,073	99
Pennsylvania	10,090.1	57,429.7	24,124	5.52	5.74	22.4	23.3	12,319	93
Philadelphia	3,205.2	16,006.5	4,759	7.83	8.09	29.0	29.9	13,516	76
Pa. Excl. Phila	6,884.9	41,423.2	19,365	4.94	5.16	20.5	21.5	12,024	100
Delaware	725.3	3,382.6	1,174	7.33	7.40	28.2	28.5	12,992	87
Maryland	3,484.0	17,321.3	6,678	7.18	7.27	27.8	27.8	13,081	99
District of Columbia	533.8	916.5	494	8.35	8.98	31.7	34.1	13,159	98
Total Northeast	41,023.6	200,303.2	61,257	6.92	7.10	27.0	27.8	12,794	72
East Central:									
Ohio	11,819.7	60,038.0	26,645	5.10	5.23	21.8	22.4	11,692	100
Indiana	8,102.2	45,544.9	19,506	4.74	4.84	21.1	21.5	11,225	96
Michigan	7,701.3	42,551.2	17,522	7.38	7.33	29.3	29.1	12,603	100
West Virginia	4,527.8	25,683.5	10,789	4.15	4.23	17.5	17.8	11,848	100
Kentucky	5,755.0	29,848.7	12,557	3.63	3.72	15.9	16.3	11,405	100
Total East Central	37,906.0	203,666.3	87,019	5.15	5.22	21.9	22.2	11,749	99
Southeast:									93
Tennessee	6,253.7	31,141.1	11,756	4.33	4.42	18.5	18.8	11,728	98
Alabama	6,631.8	34,930.7	13,935	5.19	5.25	21.8	22.1	11,910	
Mississippi	1,219.8	5,282.0	18	N.A.	N.A.	N.A.	N.A.	12,790	----
Virginia	4,441.3	22,543.5	8,322	6.54	6.63	25.1	25.5	13,001	99
North Carolina	5,371.0	30,759.4	11,467	7.02	7.05	27.4	27.5	12,822	99
South Carolina	1,665.3	9,665.5	2,969	7.35	7.40	29.0	29.2	12,677	79
Georgia	3,097.4	14,769.1	6,094	7.02	7.09	28.5	28.8	12,299	100
Florida	8,748.3	33,631.8	3,012	6.15	6.17	26.4	26.5	11,643	20
Total Southeast	37,428.6	182,723.1	57,573	5.93	5.99	24.1	24.4	12,281	78
Grand Total	116,358.2	586,692.6	205,849	5.90	6.00	24.1	24.6	12,208	83

Source: "Steam-Electric Plant Factors/1966," National Coal Association; based on data reported to the Federal Power Commission. Due to reporting limitations, the NCA study does not include all steam-electric plants.

Table 11.—Gas Consumed by Electric Utilities, Northeast, East Central and Southeast Regions, Year 1966 [1]

States	Installed capacity (000 Kw)	Net generation (MM Kwh)	Gas consumed (MM cubic feet)	Cost of gas burned (Cents/ Mcf)	Cost of gas burned (Cents/ MM Btu)	Average (Btu per cubic feet)	Percent gas/ All fuels (Btu basis)
Northeast:							
Massachusetts	3, 793. 1	19, 717. 3	9, 314	33. 7	33. 7	1, 000	5
Connecticut	2, 235. 5	12, 363. 1	352	36. 6	35. 4	1, 032	[2]
Maine	436. 6	2, 400. 8					
New Hampshire	367. 2	1, 726. 3					
Rhode Island	365. 1	1, 284. 0	226	33. 9	32. 9	1, 030	1
Vermont	30. 0	57. 8					
New Jersey	5, 991. 4	28, 749. 8	21, 187	29. 5	28. 4	1, 041	7
New York State	12, 971. 5	54, 954. 0	70, 877	37. 6	36. 1	1, 040	12
New York City	8, 909. 3	33, 776. 1	69, 107	37. 7	36. 2	1, 040	19
N.Y. excl. NYC	4, 062. 2	21, 177. 9	1, 770	35. 1	33. 6	1, 044	1
Pennsylvania	10, 090. 1	57, 429. 7	525	36. 2	34. 8	1, 041	[2]
Philadelphia	3, 205. 2	16, 006. 5					
Pa. excl. Phila	6, 884. 9	41, 423. 2	525	36. 2	34. 8	1, 041	[2]
Delaware	725. 3	3, 382. 6	3, 942	30. 8	29. 9	1, 036	12
Maryland	3, 484. 0	17, 321. 3	72	42. 0	41. 0	1, 025	[2]
District of Columbia	533. 8	916. 5					
Total Northeast	41, 023. 6	200, 303. 2	106, 495	35. 4	34. 1	1, 037	5
East Central:							
Ohio	11, 819. 7	60, 038. 0	[3] 2, 772	[3] 51. 3	[3] 50. 4	[3] 1, 017	[2]
Indiana	8, 102. 2	45, 544. 9	16, 122	26. 0	25. 2	1, 031	4
Michigan	7, 701. 3	42, 551. 2	82	47. 7	46. 6	1, 023	[2]
West Virginia	4, 527. 8	25, 683. 5	[4] 892	[4] 47. 0	[4] 42. 9	[4] 1, 100	[2]
Kentucky	5, 755. 0	29, 848. 7	747	22. 4	21. 6	1, 035	[2]
Total East Central	37, 906. 0	203, 666. 3	20, 615	26. 7	25. 9	1, 032	1
Southeast:							
Tennessee	6, 253. 7	31, 141. 1	18, 755	21. 5	20. 5	1, 050	7
Alabama	6, 631. 8	34, 930. 7	7, 020	22. 6	21. 7	1, 041	2
Mississippi	1, 219. 8	5, 282. 0	57, 074	24. 7	23. 6	1, 046	100
Virginia	4, 441. 3	22, 543. 5	1, 360	N.A.	N.A.	1, 050	1
North Carolina	5, 371. 0	30, 759. 4	2, 652	29. 5	28. 0	1, 052	1
South Carolina	1, 665. 3	9, 665. 5	18, 088	30. 4	28. 8	1, 055	20
Georgia	3, 097. 4	14, 769. 1	389	33. 0	31. 2	1, 056	[2]
Florida	8, 748. 3	33, 631. 8	93, 993	33. 2	32. 6	1, 019	27
Total Southeast	37, 428. 6	182, 723. 1	199, 331	28. 9	28. 1	1, 034	11
Grand total	116, 358. 2	586, 692. 6	326, 441	30. 9	30. 0	1, 035	5

[1] Source: "Steam-Electric Plant Factors/1966," National Coal Association; based on data reported to the Federal Power Commission. Due to reporting limitations, the NCA study does not include all steam-electric plants.

[2] Less than 0.5 per cent of total fuel consumed.

[3] Quantity and average BTU include 2,299,000 MCF of artificial gas. Cost data are for 473,000 MCF of natural gas.

[4] Quantity and average BTU include 837,000 MCF of artificial gas. Cost data are for 55,000 MCF of natural gas.

Table 12.—Fuel Oil Consumed by Electric Utilities, Northeast, East Central and Southeast Regions, Year 1966 [1]

States	Installed capacity (000 KW)	Net generation (MM Kwh)	Fuel oil consumed (000 Bbl)	Cost per barrel F.O.B. plant	Cost per barrel As Burned	Cents per MM Btu F.O.B. plant	Cents per MM Btu As burned	Average (Btu/Gal.)	Percent oil/all fuel (Btu basis)
Northeast:									
Massachusetts	3,793.1	19,717.3	16,890	$2.02	$2.04	32.2	32.4	149,445	50
Connecticut	2,235.5	12,363.1	3,477	2.09	2.11	33.2	33.5	149,983	16
Maine	436.6	2,400.8	4,306	2.11	2.13	33.5	33.9	149,883	100
New Hampshire	367.2	1,726.3	1,628	2.02	2.02	32.0	32.2	149,336	55
Rhode Island	365.1	1,284.0	980	2.09	2.16	33.4	34.5	148,926	37
Vermont	30.0	57.8	---	---	---	---	---	---	---
New Jersey	5,991.4	28,749.8	14,918	1.94	1.96	30.9	31.1	149,722	32
New York State	12,971.5	54,954.0	28,626	1.98	2.00	31.7	32.1	148,821	30
New York City	8,909.3	33,776.1	28,583	1.98	2.00	31.7	32.1	148,821	46
N.Y. Excl. NYC	4,062.2	21,177.9	43	2.66	2.47	42.5	39.5	149,059	[2]
Pennsylvania	10,090.1	57,429.7	6,677	2.04	2.05	32.0	32.2	151,562	7
Philadelphia	3,205.2	16,006.5	6,531	2.00	2.01	31.4	31.5	151,861	24
Pa. excl. Phila	6,884.9	41,423.2	146	4.06	4.03	70.0	69.4	138,177	[2]
Delaware	725.3	3,382.6	52	3.04	3.04	50.0	50.0	146,467	1
Maryland	3,484.0	17,321.3	177	2.82	2.82	45.7	45.7	148,050	1
District of Columbia	533.8	916.5	32	N.A.	N.A.	N.A.	N.A.	150,000	2
Total Northeast	41,023.6	200,303.2	77,763	2.00	2.02	31.9	32.2	149,485	23
East Central:									
Ohio	11,819.7	60,038.0	80	4.09	4.15	69.2	71.9	140,809	[2]
Indiana	8,102.2	45,544.9	88	3.92	3.92	67.3	67.3	139,042	[2]
Michigan	7,701.3	42,551.2	13	3.94	3.94	68.2	68.2	137,546	[2]
West Virginia	4,527.8	25,683.5	43	4.06	4.14	70.4	71.9	137,239	[2]
Kentucky	5,755.0	29,848.7	2	3.89	3.99	65.9	67.6	140,476	[2]
Total East Central	37,906.0	203,666.3	226	4.01	4.05	68.5	69.2	139,275	---
Southeast:									
Tennessee	6,253.7	31,141.1	---	---	---	---	---	---	---
Alabama	6,631.8	34,930.7	34	N.A.	N.A.	N.A.	N.A.	150,000	[2]
Mississippi	1,219.8	5,282.0	18	3.20	3.20	49.7	49.7	151,984	[2]
Virginia	4,441.3	22,543.5	70	4.17	4.30	69.4	75.9	143,027	[2]
North Carolina	5,371.0	30,759.4	33	4.36	4.41	73.7	74.7	140,777	[2]
South Carolina	1,665.3	9,665.5	121	2.32	2.32	37.0	37.0	149,397	1
Georgia	3,097.4	14,769.1	33	3.94	3.97	68.1	68.6	137,662	[2]
Florida	8,748.3	33,631.8	30,026	2.10	2.09	33.4	33.[illegible]	149,578	53
Total Southeast	37,428.6	182,723.1	30,335	2.11	2.10	33.6	33.4	149,539	11
Grand total	116,358.2	586,692.6	108,324	2.03	2.05	32.3	32.7	149,479	11

[1] Source: "Steam-Electric Plant Factors/1966," National Coal Association; based on data reported to the Federal Power Commission. Due to reporting limitations, the NCA study does not include all steam-electric plants.

[2] Less than 0.5 percent of total fuel consumed.

Table 13.—Minemouth Electric Plants of 500 Megawatts Capacity and Over, Northeast, East Central and Southeast Regions [1]

Plant	Megawatts	Operational	Operator
PLANTS IN OPERATION PRIOR TO 1967			
Paradise No. 1	700	1963	T.V.A.
Paradise No. 2	700	1963	T.V.A.
Tanners Creek No. 4	580	1964	Indiana Michigan Electric Co. (AEPCO).
Mt. Storm No. 1	570	1965	VEPCO.
Mt. Storm No. 2	570	1966	VEPCO.
Total	3, 120		
NEW PLANTS AND ADDITIONS SCHEDULED FOR 1967 TO 1973 SERVICE			
Paradise No. 3	1, 130	1969	T.V.A.
Keystone No. 1	865	1967	Keystone group of Pa.-N.Y.-Md. Pool.
Keystone No. 2	865	1968	Do.
Conemaugh No. 1	841	1970	Conemaugh group of Pa.-N.Y.-Md. Pool.
Conemaugh No. 2	841	1971	Do.
Big Sandy No. 2	800	1969	Kentucky Power Co. (AEPCO System).
Mitchell No. 1	800	1970	Appalachian Power Co. (AEPCO System).
Mitchell No. 2	800	1971	Do.
Homer City No. 1	640	1969	Pa. Electric Co. & N.Y.S. Gas & Elec. Co.
Homer City No. 2	640	1970	Do.
Cardinal No. 1	615	1967	Ohio Power Co. and Buckeye Power, Inc.
Cardinal No. 2	615	1967	Do.
Muskingum River No. 5	615	1968	Ohio Power Co. (AEPCO System).
Sammis No. 6	600	1968	Ohio Edison Co. and Cleveland Elec. Illum. Co.
Sammis No. 7	600	1971	Do.
J. M. Stuart No. 1	600	1970	Cincinnati Gas & Elec. Co.; Columbus & Southern Ohio Elec. Co.; Dayton Power & Light Co.
J. M. Stuart No. 2	600	1972	Do.
J. M. Stuart No. 3	600	1973	Do.
Conesville No. 7	600	1973	Do.
Ft. Martin No. 1	500	1967	Allegheny Power System & Duquesne Light Co.
Ft. Martin No. 2	500	1968	Allegheny Power System.
Hatsfield Ferry No. 1	540	1969	Do.
Hatsfield Ferry No. 2	540	1970	Do.
Hatsfield Ferry No. 3	540	1972	Do.
Cheswick No. 1	500	1970	Duquesne Light Co.
Cayuga No. 1	500	1970	Public Service Co. of Indiana, Inc.
Cayuga No. 2	500	1972	Do.
Total	17, 787		

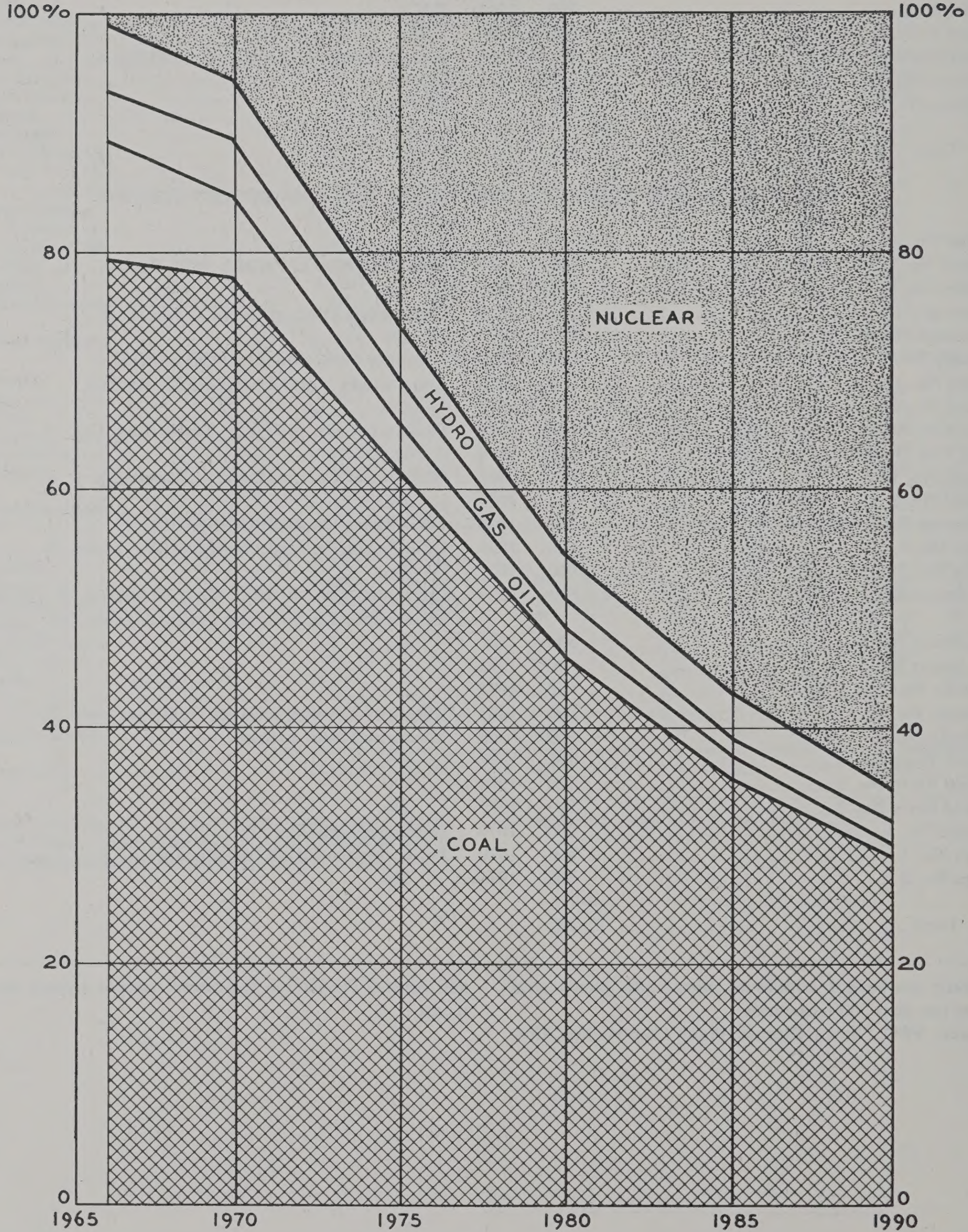
[1] There are several additional minemouth plants with units of less than 500 megawatts.

Source: FPC "Steam-Electric Plant Construction Cost and Annual Production Expenses," various annual supplements.

PERCENT GENERATION BY TYPE OF FUEL AND HYDRO POWER

NORTHEAST, EAST CENTRAL AND SOUTHEAST REGIONS COMBINED

Years 1966-1990

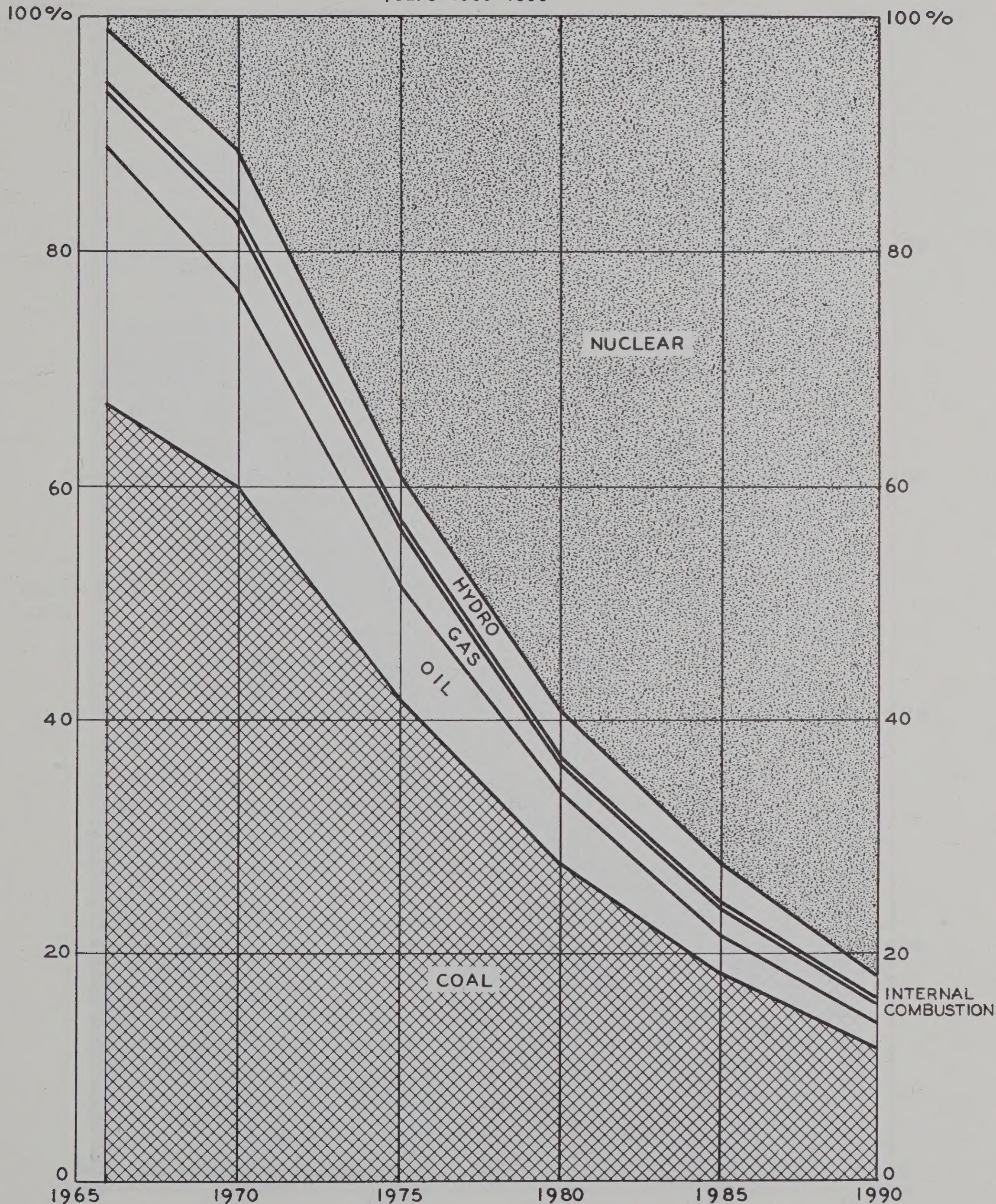


Based on Survey by
Fossil Fuel Resources Committee

PERCENT GENERATION BY TYPE OF FUEL AND HYDRO POWER

NORTHEAST REGION

Years 1966-1990



Based on Survey by
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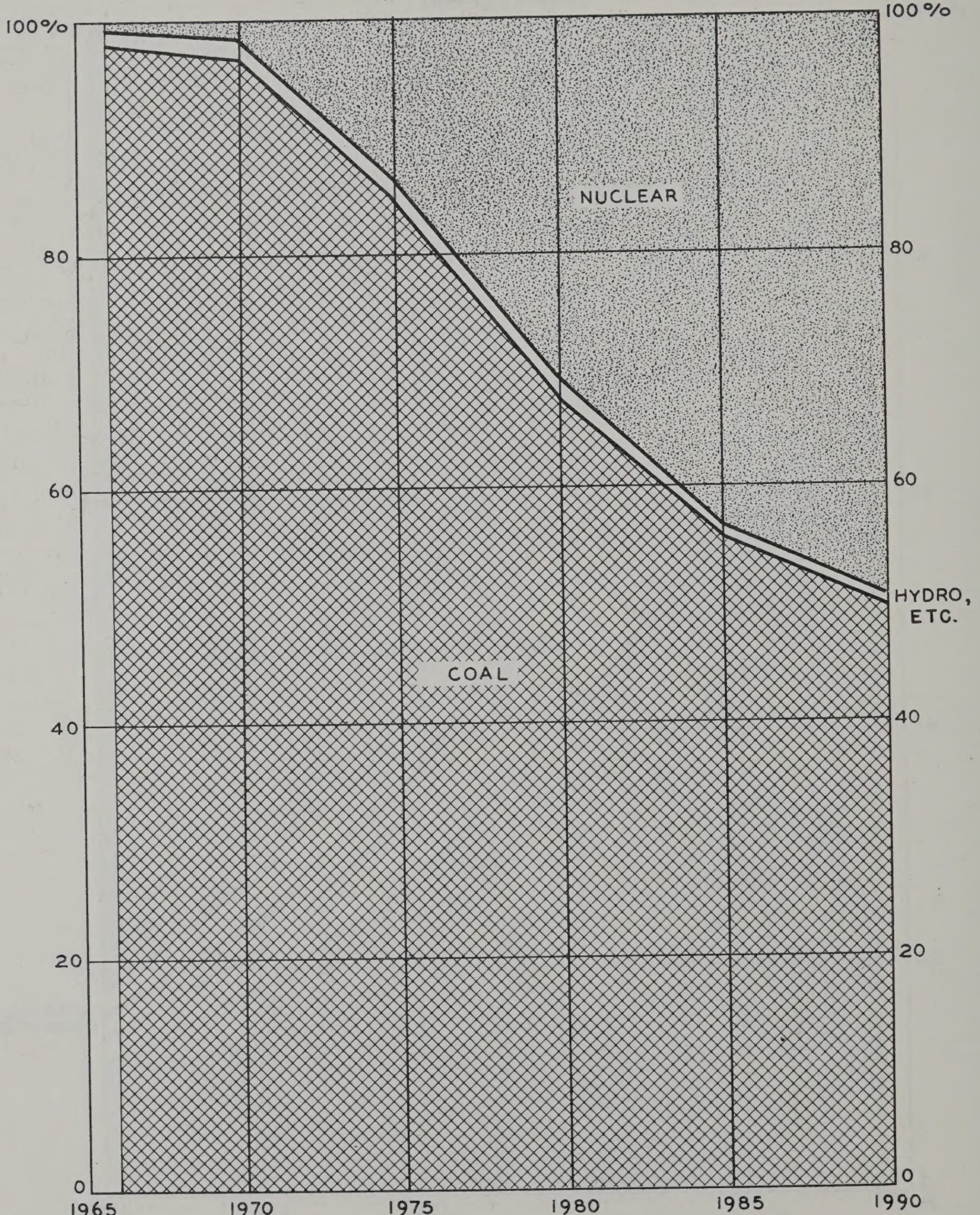
PERCENT GENERATION BY TYPE OF FUEL AND HYDRO POWER

EAST CENTRAL REGION

Years 1966-1990



Based on Survey by
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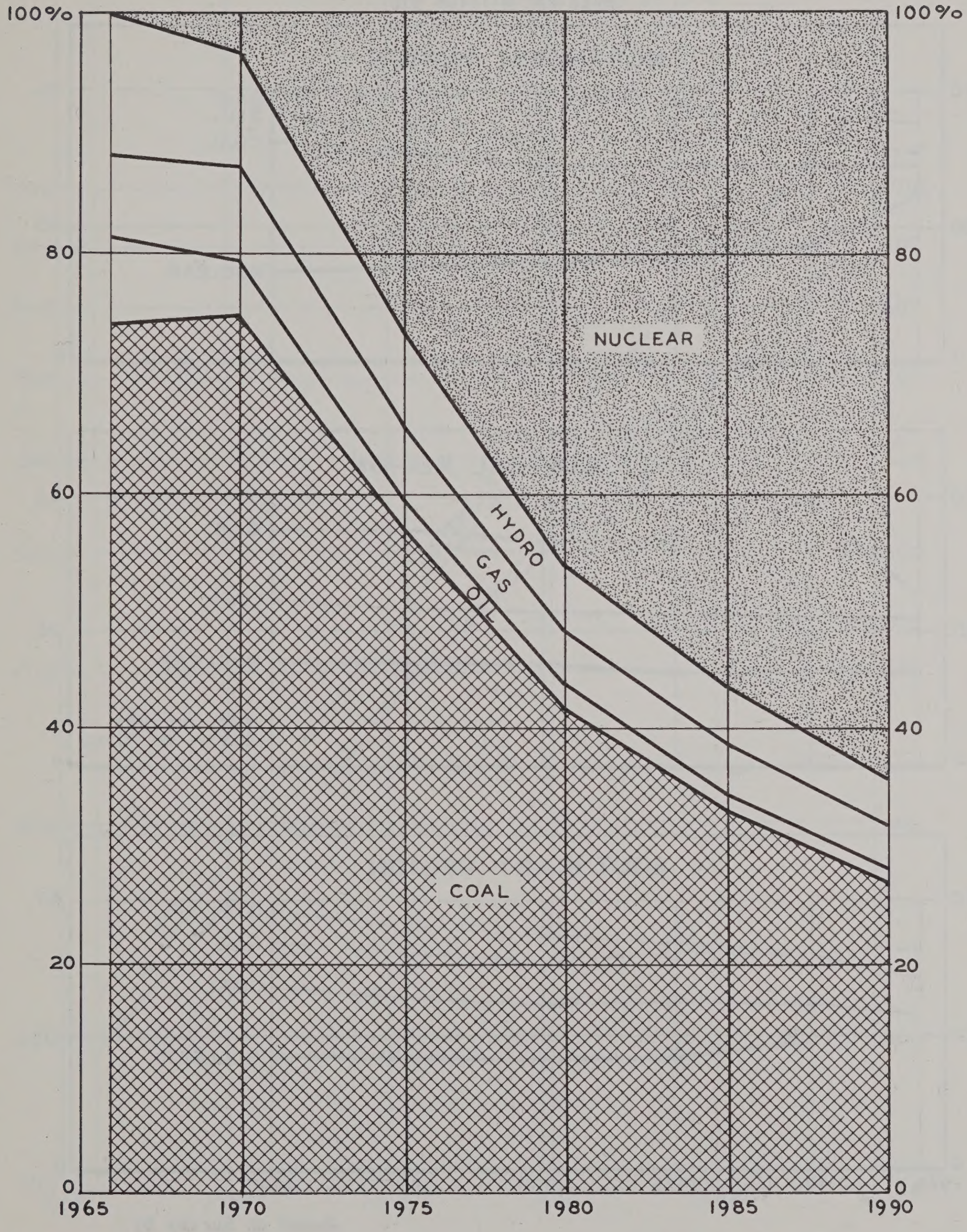
CHART 4

PERCENT GENERATION BY TYPE OF FUEL AND HYDRO POWER

SOUTHEAST REGION

Years 1966-1990



Based on Survey by
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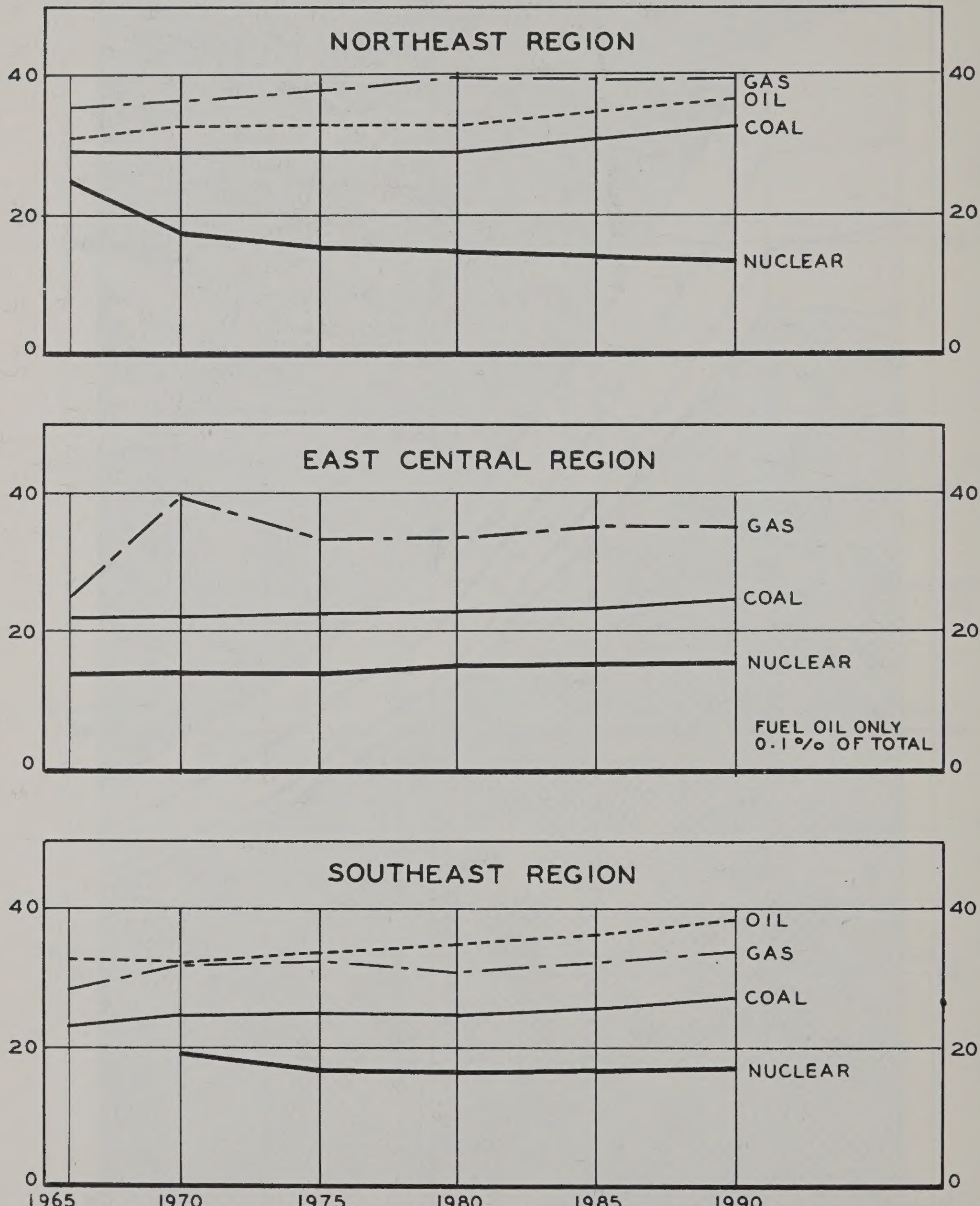
COST OF FUEL FOR ELECTRIC GENERATION

Years 1966-1990

Cents Per Million BTU



Based on Survey by
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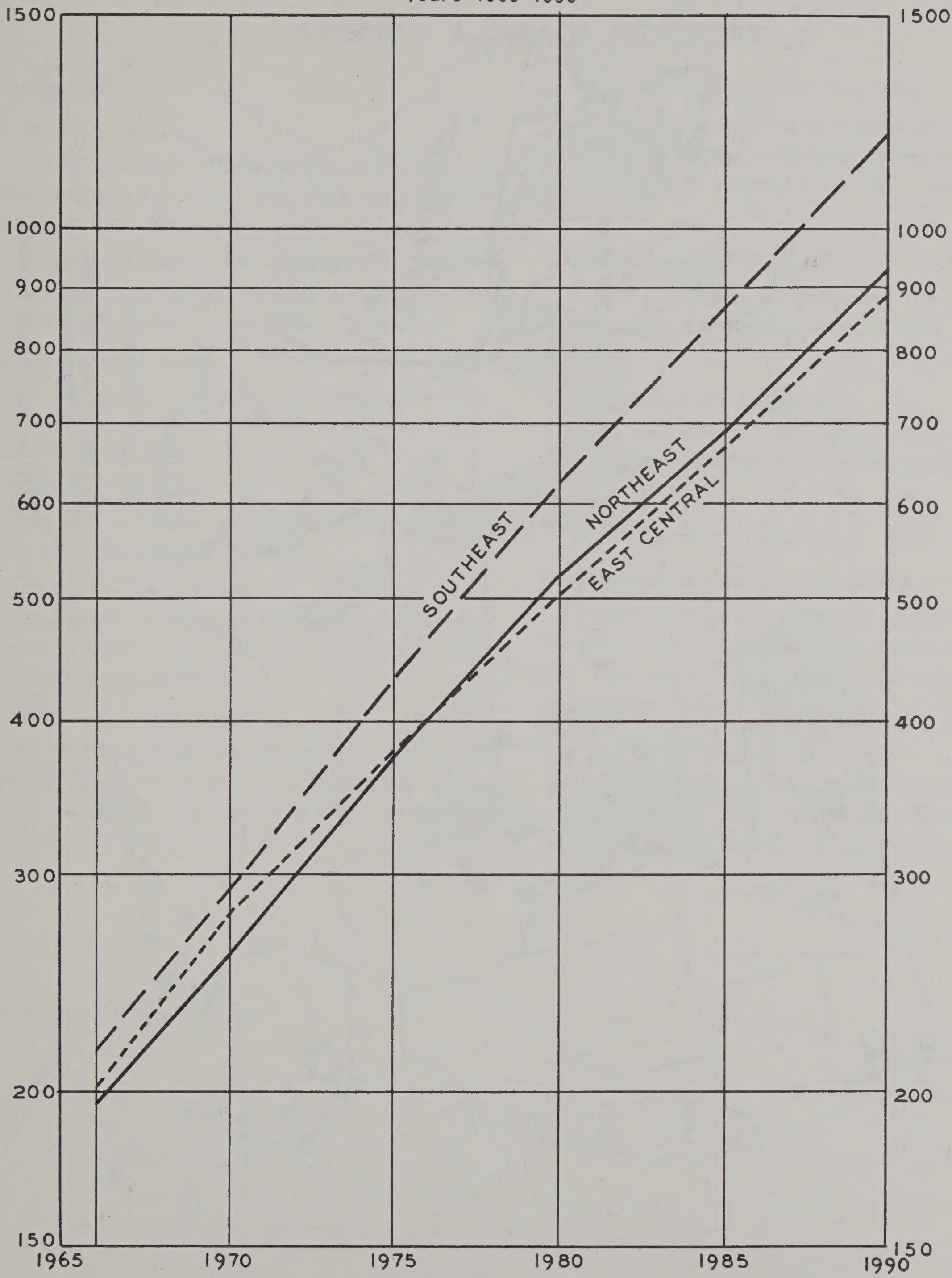
CHART 6

ELECTRIC GENERATION BY FUELS AND HYDRO POWER

NORTHEAST, EAST CENTRAL AND SOUTHEAST REGIONS

BILLION KILOWATTHOURS

Years 1966-1990



Based on Survey by
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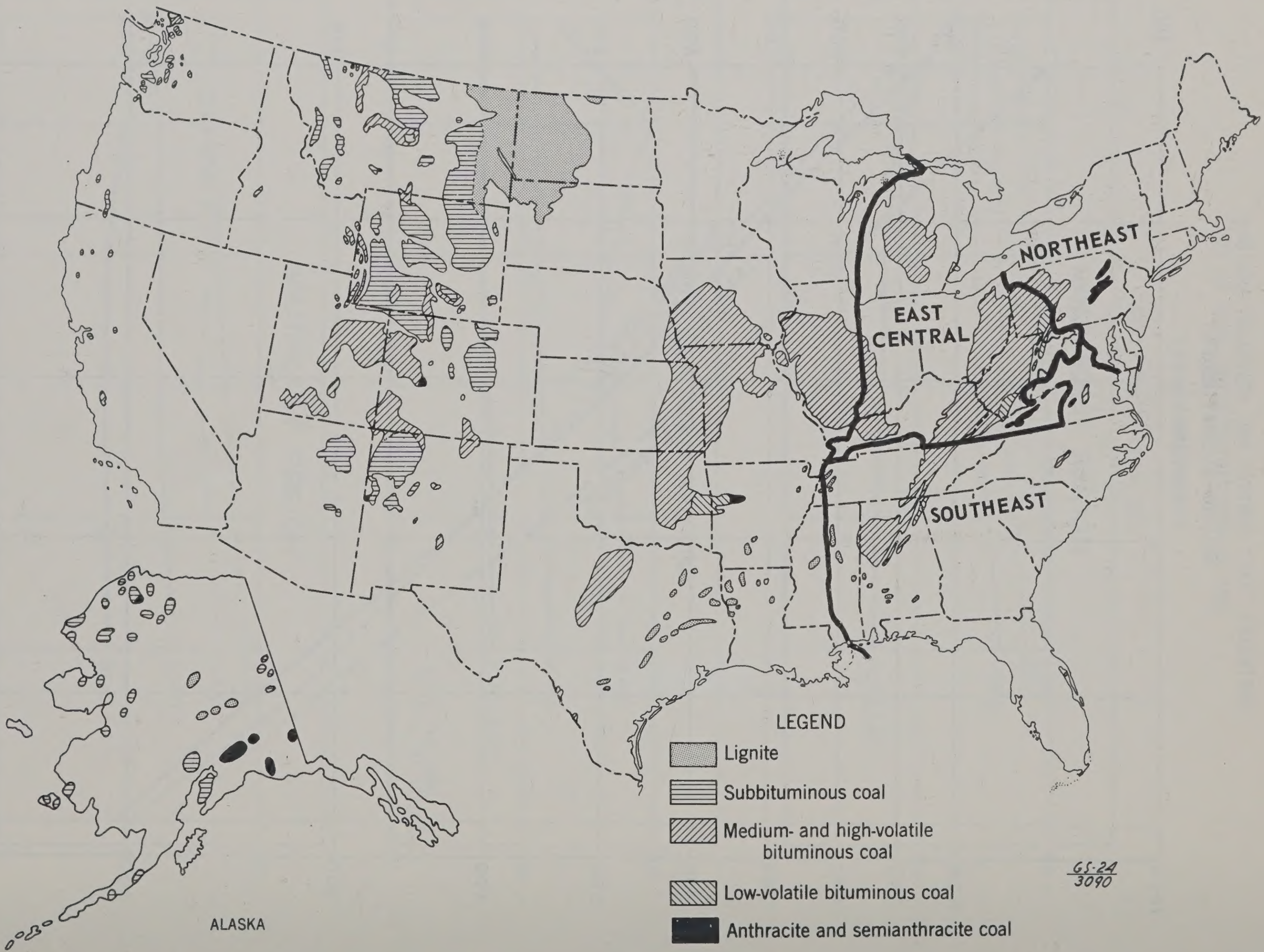
COAL FIELDS OF THE UNITED STATES



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MAP 2

APPENDIX A—STACK PROCESSES

Extraction

1. *Reinluft Process*

SO_2 is absorbed from the flue gases by char, and then removed as sulfuric acid. High costs and char problems have discouraged commercial use.

2. *Alkalized Alumina (Bureau of Mines)*

Another absorption process, developing elemental sulfur as the end product.

3. *DAP—Mn Process*

An absorption process using manganese oxide. Ammonia is required to develop the ammonium sulfate end product.

4. *Catalytic Oxidation*

The SO_2 is oxidized to SO_3 which forms sulfuric acid when the gases are cooled.

5. *Kiyoura—T.I.T. Process*

Similar to the catalytic oxidation process. Ammonia is injected to react with the SO_3 and form ammonium sulfate crystals.

6. *Wellman-Lord Process*

An absorbing fluid removes the SO_2 from the flue gas. This fluid is then heated in a stripping column to release dry SO_2 gas which can then be converted to elemental sulfur or sulfuric acid.

7. *Molten Salt (Atomics International)*

A scrubbing process using molten salt to remove SO_2 from flue gases would form sodium sulfite. The sulfite would be reduced to produce sulfur or sulfuric acid.

8. *Dual Cycle Regenerative Process*

A wet scrubbing process using the controlled vortex reactor, with recovery of SO_2 from the solution.

9. *Chromatographic Separation*

A wet scrubbing process using selective absorption in a regenerable liquid dispersed on a solid surface.

Additive

1. *Dolomite—Combustion Engineering*

Limestone or dolomite are used to react with the SO_2. Both wet and dry systems are under consideration. Pilot plant work has been done and a full size unit has been ordered.

2. *Wet Scrubbers*

A wet process, involving a proprietary static mixing device. Particulates and SO_2 are scrubbed out of the stack gases when a caustic solution is used.

APPENDIX B—DEFINITION OF BITUMINOUS COAL AND LIGNITE PRODUCING DISTRICTS

DISTRICT 1.—EASTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All mines east of the Allegheny River, and those mines served by the Pittsburgh & Shawmut Railroad located on the west bank of the river.

Fayette County (part).—All mines located on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines not served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties: Bedford, Blair, Bradford, Cambria, Cameron, Centre, Clairon, Clearfield, Clinton, Elk, Forest, Fulton, Huntingdon, Jefferson, Lycoming, McKean, Mifflin, Potter, Somerset, and Tioga.

Maryland.—All mines in the State.

West Virginia.—All mines in the following counties: Grant, Mineral, and Tucker.

DISTRICT 2.—WESTERN PENNSYLVANIA

Pennsylvania.—Armstrong County (part).—All mines west of the Allegheny River except those mines served by the Pittsburgh & Shawmut Railroad.

Fayette County (part).—All mines except those on and east of the line of Indian Creek Valley branch of the Baltimore & Ohio Railroad.

Indiana County (part).—All mines served by the Saltsburg branch of the Pennsylvania Railroad.

Westmoreland County (part).—All mines except those served by the Pennsylvania Railroad from Torrance, east.

All mines in the following counties: Allegheny, Beaver, Butler, Greene, Lawrence, Mercer, Venango, and Washington.

DISTRICT 3.—NORTHERN WEST VIRGINIA

West Virginia.—Nicholas County (part).—All mines served by or north of the Baltimore & Ohio Railroad.

All mines in the following counties: Barbour, Braxton, Calhoun, Doddridge, Gilmer, Harrison, Jackson, Lewis, Marion, Monongalia, Pleasants, Preston, Randolph, Ritchie, Roane, Taylor, Tyler, Upshur, Webster, Wetzel, Wirt, and Wood.

DISTRICT 4.—OHIO

All mines in the State.

DISTRICT 5.—MICHIGAN

All mines in the State.

DISTRICT 6.—PANHANDLE

West Virginia.—All mines in the following counties: Brookie, Hancock, Marshall, and Ohio.

DISTRICT 7.—SOUTHERN NO. 1

West Virginia.—Fayette County (part).—All mines east of Gauley River and all mines served by the Gauley River branch of the Chesapeake & Ohio Railroad and mines served by the Virginian Railway.

McDowell County (part).—All mines in that portion of the county served by the Dry Fork Branch of the Norfolk & Western Railroad and east thereof.

Raleigh County (part).—All mines except those on the Coal River Branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part).—All mines in that portion served by the Gilbert branch of the Virginian Railway lying east of the mouth of Skin Fork of Guyandot River and in that portion served by the main line and the Glen Rogers branch of the Virginian Railway.

All mines in the following counties: Greenbrier, Mercer, Monroe, Pocahontas, and Summers.

Virginia.—Buchanan County (part).—All mines in that portion of the county served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad and in that portion on the headwaters of Dismal Creek east of Lynn Camp Creek (a tributary of Dismal Creek).

Tazewell County (part).—All mines in those portions of the county served by the Dry Fork branch to Cedar Bluff and from Bluestone Junction to Boissevain branch of the Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Montgomery, Pulaski, Wythe, Giles, and Craig.

DISTRICT 8.—SOUTHERN NO. 2

West Virginia.—Fayette County (part).—All mines west of the Gauley River except mines served by the Gauley River branch of the Chesapeake & Ohio Railroad.

McDowell County (part).—All mines west of and not served by the Dry Fork branch of the Norfolk & Western Railroad.

Nicholas County (part).—All mines in that part of the county south of and not served by the Baltimore & Ohio Railroad.

Raleigh County (part).—All mines on the Coal River branch of the Chesapeake & Ohio Railroad and north thereof.

Wyoming County (part). All mines in that portion served by the Gilbert branch of the Virginian Railway and lying west of the mouth of Skin Fork of Guyandot River.

All mines in the following counties: Boone, Cabell, Clay, Kanawha, Lincoln, Logan, Mason, Mingo, Putnam, and Wayne.

Virginia.—Buchanan County (part).—All mines in the county, except in that portion on the headwaters of Dismal Creek, east of Lynn Camp Creek (a tributary of Dismal Creek) and in that portion served by the Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

Tazewell County (part).—All mines in the county except in those portions served by the Dry Fork branch of the Norfolk & Western Railroad and branch from Bluestone Junction to Boissevain of Norfolk & Western Railroad and Richlands-Jewell Ridge branch of the Norfolk & Western Railroad.

All mines in the following counties: Dickinson, Lee, Russell, Scott, and Wise.

Kentucky.—All mines in the following counties in eastern Kentucky: Bell, Boyd, Breathitt, Carter, Clay, Elliott, Floyd, Greenup, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lawrence, Lee, Leslie, Letcher, McCreary, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Wayne, and Whitley.

Tennessee.—All mines in the following counties: Anderson, Campbell, Claiborne, Cumberland, Fentress, Morgan, Overton, Roane, and Scott.

North Carolina.—All mines in the State.

DISTRICT 9.—WEST KENTUCKY

Kentucky.—All mines in the following counties in western Kentucky: Butler ,Christian, Crittenden, Daviess, Hancock, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Simpson, Todd, Union, Warren, and Webster.

DISTRICT 10.—ILLINOIS

All mines in the State.

DISTRICT 11.—INDIANA

All mines in the State.

DISTRICT 12.—IOWA

All mines in the State.

DISTRICT 13.—SOUTHEASTERN

Alabama.—All mines in the State.

Georgia.—All mines in the following counties: Dade and Walker.

Tennessee.—All mines in the following counties: Bledsoe, Grundy, Hamilton, Marion, McMinn, Rhea, Sequatchie, Van Buren, Warren, and White.

DISTRICT 14.—ARKANSAS-OKLAHOMA

Arkansas.—All mines in the State.

Oklahoma.—All mines in the following counties: Haskell, Le Flore, and Sequoyah.

DISTRICT 15.—SOUTHWESTERN

Kansas.—All mines in the State.

Texas.—All mines in the State.

Missouri.—All mines in the State.

Oklahoma.—All mines in the following counties: Coal, Craig, Latimer, Muskogee, Okmulgee, Pittsburg, Rogers, Tulsa, and Wagoner.

DISTRICT 16.—NORTHERN COLORADO

All mines in the following counties in the State: Adams, Arapahoe, Boulder, Douglas, Elbert, El Paso, Jackson, Jefferson, Larimer, and Weld.

DISTRICT 17.—SOUTHERN COLORADO

Colorado.—All mines except those included in District 16.

New Mexico.—All mines except those included in District 18.

DISTRICT 18.—NEW MEXICO

New Mexico.—All mines in the following counties: Grant, Lincoln, McKinley, Rio Arriba, Sandoval, San Juan, San Miquel, Santa Fe, and Socorro.

Arizona.—All mines in the State.

California.—All mines in the State.

DISTRICT 19.—WYOMING

Wyoming.—All mines in the State.

Idaho.—All mines in the State.

DISTRICT 20.—UTAH

All mines in the State.

DISTRICT 21.—NORTH DAKOTA-SOUTH DAKOTA

All mines in North Dakota and South Dakota.

DISTRICT 22.—MONTANA

All mines in the State.

DISTRICT 23.—WASHINGTON

Washington.—All mines in the State.

Oregon.—All mines in the State.

Alaska.—All mines in the State.

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